EPCOR Natural Gas Limited Partnership

Cost of Service Application

EB-2024-0130

July 22, 2024

Exhibit 1 – Administrative Documents

PROVIDING MORE

Contents

CERTIFICATION OF EVIDENCE

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

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

2. This certificate is given pursuant to the Ontario Energy Board's (the "**Board**") Filing Requirements for Filing Requirements For Natural Gas Distribution Rate Applications dated February 16, 2017;

3. The evidence submitted in support of ENGLP's Application for rates effective on January 1, 2025 filed with the Board is accurate, consistent and complete to the best of my knowledge;

4. The distributor has processes and internal controls in place for the preparation, review, verification and oversight of the account balances being disposed;

5. Shared service and affiliate costs are in compliance with the Board's *Affiliate Relationship Code for Gas Utilities*; and

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

DATED this 22nd day of July, 2024.

____

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

1.1. Administrative Documents

1.1.1. Application Summary & Overview

EPCOR Natural Gas Limited Partnership ("**ENGLP**") is pleased to present its Cost of Service application for rates effective January 1, 2025. This application consists of the following Exhibits and Excel models as evidence to support this application:

- Exhibit 1: Administrative Documents
- Exhibit 2: Rate Base and Utility System Plan
- Exhibit 3: Operating Revenue
- Exhibit 4: Operating Expenses
- Exhibit 5: Cost of Capital and Capital Structure
- Exhibit 6: Revenue Requirement and Revenue Deficiency
- Exhibit 7: Cost Allocation
- Exhibit 8: Rate Design
- Exhibit 9: Deferral and Variance Accounts
- Exhibit 10: Incentive Rate-Setting Proposal

- ENGLP_EB-2024-0130_Supporting Appendixes
- ENGLP_EB-2024-0130 Load Forecast
- ENGLP_EB-2024-0130 Revenue Requirement
- ENGLP_EB-2024-0130_Cost Allocation Model
- ENGLP_EB-2024-0130_DVA Continuity Schedule
- ENGLP_EB-2024-0130_ Rate Model (including bill impacts)

All documents have been submitted to the Ontario Energy Board ("**OEB**") via the RESS on-line portal. The application along with all supporting evidence will also be posted on the utility's website and customers informed of the filing via social media and bill notification once the Application is accepted by the OEB.

1.2. Executive Summary

The applicant is ENGLP with offices in the Town of Aylmer and the Municipality of Kincardine. ENGLP is a wholly-owned indirect subsidiary of EPCOR Utilities Inc. ("**EUI**"). The general partner of ENGLP is EPCOR Ontario Utilities Inc. ("**EOUI**"), and the sole limited partner is EPCOR Commercial Services Inc., which are both subsidiaries of EUI.

ENGLP has two areas of operations which are regulated by two separate and distinct rate structures and rate bases. The most recently approved rate frameworks include:

- ENGLP Aylmer - EB-2018-0336 (5 year term from 2020-2024); and,
- ENGLP Southern Bruce - EB-2018-0264 (10 year custom IR from 2019-2028).

This Application is for distribution rates for the Aylmer service territory only and 'ENGLP' is used in this application in reference to Aylmer. ENGLP distributes natural gas to over 10,200 customers in and around Aylmer, Ontario, with its service area stretching from south of Highway 401 to the shores of Lake Erie, from Port Bruce in the west to Clear Creek in the east. ENGLP provides natural gas service to customers in the Townships of Malahide and South-West Oxford; Municipalities of Bayham, Thames Centre and Central Elgin, and Norfolk County. The system serves the individual communities of Aylmer, Belmont, Brownsville, Port Burwell, Springfield, Straffordville, and Vienna. The gas demands in the ENGLP System are mainly for residential and commercial heating, small industrial users, greenhouse and grain drying. In addition, the system provides service to IGPC Ethanol Inc. ("**IGPC**"), a large industrial customer that is served using a standalone distribution system.

As a small utility, ENGLP Aylmer does not prepare a stand-alone business plan. In the absence of this, ENGLP is following the OEB guidance provided for electricity distributors which states:

> *"In the absence of a business plan, the distributor must provide key planning assumptions, a description of material factors (internal and external) that may affect the operation of the distributor and major goals of the distributor in the*

test year and remaining years of the five-year term."[1]

Key Planning Assumptions

ENGLP has developed this Application under the priorities of:

- Providing safe and reliable service to customers;
- Supporting a changing, diverse customer base, while providing system access to new customers;
- Alignment with public policy (including Energy Transition);
- Supporting operational effectiveness and efficiency leading with a safety driven culture; and,
- Prioritizing financial performance as a utility

The Utility System Plan ("**USP**") included in this Application is the foundational input into the business planning assumptions providing the next five years of utility investment priorities. These investments are required to ensure that ENGLP will achieve its objectives and the performance measures set by both the OEB and EPCOR itself.

A critical planning input is customer feedback. ENGLP has carried out various customer engagements since acquiring the utility in 2017 with customers advising that their priorities include affordability and reliability. While there is general support for investment in these areas, ENGLP's customers have also stated that they are sensitive to rates.

In response to customer feedback, ENGLP has developed a prudent five-year capital investment and maintenance plan to ensure the reliability and sustainability of its distribution network. ENGLP has aimed for a consistent capital budget envelope for the USP period that balances mandatory (immediately required) investments with non-mandatory needs (other required investments) through a project pacing and prioritization process. This includes capital investments related to organic customer growth; reinforcement projects to maintain system pressure and add capacity

[1] Filing Requirements For Electricity Distribution Rate Applications - 2023 Edition for 2024 Rate Applications, Chapter 2, Section 2.1.2., page 7

to meet growth in demand from existing customers; projects to maintain and enhance the safety and reliability of ENGLP assets and to ensure compliance with relevant codes and regulations; and programs related to the replacement of plant, vehicles, equipment, computer hardware and software as a result of age and condition. Overall, the capital spend profile supports customer growth, permits asset integrity replacements, and maintains the system in a safe and reliable manner.

There are many challenges in the energy transition away from carbon-based fuels, including the natural gas system, as a result of shifting customer values and preferences and the overall shift to a clean energy economy. Natural gas has long played an important role in the energy system of Ontario, as a source of power for electricity generation, as a fuel for home heating and cooking and as a feedstock and source of process heat for industry. It is clear that natural gas will continue to play these critical roles in the short- to medium-term. Longer-term prospects, particularly for home heating, are less clear as society transitions to net zero.

The speed at which customers may change their heating source is uncertain. It will depend on a large number of individual factors, including equipment age and personal preferences and values, as well as system-level and policy factors, such as cost development, availability of equipment and qualified technicians, and supportive policies and incentives. The combination of such factors could lead to customers disconnecting from the natural gas system absent any personal motivation to lower their carbon footprint.

Moving forward, EPCOR's Asset Management Plan must be prudent and ensure that it has accounted appropriately for the risk arising from the energy transition. There are a number of examples of such prudent consideration of energy transition in EPCOR's USP, including facilitating the connection of RNG and the use of local production and existing gathering assets in response to customer connection requests rather than increase the demand on the transmission system. EPCOR will continue to monitor any energy transition policy as outlined by the provincial government and associated regulation under the purview of the OEB and update its USP and customer communication outreach as necessary.

The planning assumptions and approaches used to develop both the strategic direction of ENGLP and its USP include the following:

a) ENGLP's load service requirement for each of the towns within the Aylmer distribution system will continue to grow at approximately 2% per annum;

b) ENGLP's load service requirement for non-town (rural) loads are assessed and analyzed on an individual basis. This involves analyzing whether new distribution mains or reinforcements to existing mains are required to service these loads. There are two planned large customer additions during this USP period. The first is an agricultural customer, who has requested that ENGLP provide natural gas for Phase 1 and Phase 2 of their operations. The second is the development of a 5MW natural gas fired power plant addition in the Aylmer distribution area, whose main fuel source would be grid gas from ENGLP;

c) ENGLP will conduct reinforcement projects in its system to maintain minimum system pressures for demand of gas to be met on design day conditions. These projects involve installing new gas infrastructure or modifying existing gas assets to maintain system pressure, capacity and meet growth demands. The Port Burwell Low Pressure Reinforcement and South Belmont Pipe Additions are two projects planned during this USP period to address low pressure conditions in the distribution system;

d) ENGLP will continue to evolve its asset inspection and maintenance program to optimize the asset lifecycle, further refining the ability to preemptively recognize the time that the asset has reached a condition requiring refurbishment or replacement, thereby requiring capital investment;

e) ENGLP will continue to address any integrity and reliability issues associated with the operation of the 6" nominal pipe size ("**NPS**") steel pipeline that serves IGPC's ethanol plant in Aylmer;

f) ENGLP will continue to invest in Supervisory Control and Data Acquisition ("**SCADA**"), as well as GIS, which plays a central role in its asset register and thereby enhances asset management. In the future, recording of assets' inspections and condition assessment will be introduced into the GIS environment, contributing to a better overall understanding of assets that will lead to more efficient and optimized design, maintenance and investment activities. Further, ENGLP will utilize Synergi Gas software for annual distribution system planning and integrity study purposes;

g) Cybersecurity will continue to be a growing risk requiring increased investment, and as such, ENGLP will implement the necessary tools to stay ahead of threats and maintain compliance within the Ontario Cyber Security Framework; and,

h) ENGLP has planned for the replacement of fleet, including evaluating existing fleet assessed at economic end-of -life ready to be traded for new fleet units.

ENGLP's planning process covers the five focus areas of:

- **Health, Safely and Environment**
    - Improved culture around psychological safety and respectful workplace leading to willingness to share and continue to learn from past experiences.
    - Becoming a procedurally-based operation:
        - ENGLP has made concerted efforts to develop Standard Operating Procedures and an Operations & Maintenance manual over the past five years. This has been influenced by lessons learned during the construction of the greenfield South Bruce project, which demonstrated the need for improved standards and contracted support.
    - Improved Contractor Safety Management:
        - ENGLP has established an alliance partnership with Aecon Utilities (**"Aecon**") under a Master Service Agreement to ensure that all of ENGLP's newly constructed assets are built to industry standards and in accordance with TSSA regulations.
    - A focus on compliance and competency training status.
    - Effective management of public safety through communication.
- **People**
    - Improving engagement by demonstrating that ENGLP listens to its people and deliver on its commitments
    - Growing and developing employees:
        - ENGLP has focused on developing training and procedures for its newly hired technicians. There have also been two employees trained to Gas

Fitter 1 status to ensure coverage in this area.

- Improving communications channels internally.
- Making diversity, equity and inclusion ("**DEI**") an integral aspect of culture.

- **Operations Excellence**
  - Improved capital planning processes:
    - ENGLP has contracted out much of its capital construction over the past five years to address the cyclical nature of capital projects and to access certain skill sets, allowing internal resources to focus on O&M activities (asset inspections, valve and regulating station maintenance, locates). This has involved focusing on contractor management with a recently developed quality assurance and control program ("**QA/QC**").
  - Developing technology and data collection strategy:
    - ENGLP has upgraded its SCADA system over the previous five-year period, and will continue to add SCADA points to improve on situational awareness, which reduces reliability risk.
  - Improving emergency preparedness:
    - ENGLP has ensured that it has the resources available to respond to emergencies on its assets. In particular, ENGLP has contracted with a third-party contractor to ensure that resources are available to respond to integrity issues along its steel pipeline assets.
- **Customer & Stakeholders**
  - Improved customer experience (through public facing tools, contractor management for new connections).
  - Improved commercial and industrial customer integration (through the creation of a customer connection policy included as Exhibit 2, Tab 3, Schedule 2).
  - Improved EPCOR brand in ENGLP's operations areas.
- **Shareholder Value**
  - Deliver on financial objectives.
  - Meet all regulatory filing obligations.
  - Improved EPCOR brand in our area of operations.

The remaining sections of the Application are constructed under these five fundamental planning assumptions.

1.3. Administration

1.3.1. Primary Contact for Application

The Applicant’s primary EPCOR contact and address for this Application is as follows:

Tim Hesselink
Senior Manager, Regulatory Affairs
EPCOR Electricity Distribution Ontario Inc.
43 Stewart Road
Collingwood, Ontario L9Y 4M7

Telephone:(705) 445-1800 ext. 2274
E-Mail:thesselink@epcor.com

1.3.2. Legal Representation for Application

The Applicant’s internal counsel is as follows:

Tayler Meagher
Legal Counsel
EPCOR Utilities Inc.
2000 – 10423 101 Street NW
Edmonton, Alberta T5H 0E8

Telephone:(780) 412-3270
E-Mail:tmeagher@epcor.com

The Applicant’s external counsel is as follows:

Richard King
Osler, Hoskin & Harcourt LLP
100 King Street West
1 First Canadian Place
Suite 6200, PO Box 50
Toronto, ON M5X 1B8

Telephone: (416) 862-6626
Fax:(416) 862-6666
E-Mail:rking@osler.com

1.3.3. Applicant's Internet and Social Media Addresses

ENGLP will make a copy of this Application available at the following internet address:

https://www.epcor.com/account-billing/rate-applications/Pages/default.aspx

Confirmation that ENGLP has filed an Application and details as to where it can be accessed will also be communicated to customers via a statement included in customers' bills.

ENGLP's general website address is as follows:

https://www.epcor.com/Pages/Home.aspx?mylocation=aylmer_ontario

1.3.4. Customer Email Addresses

ENGLP has record of email addresses for approximately 53% of customers.

Rate Class	Email Address	Percentage
R1	5364	53%
R2	24	48%
R3	5	100%
R4	23	52%
R5	4	100%
R6	1	100%
Total	**5421**	**53%**

1.3.5. Billing Cycles

ENGLP bills customers on an ongoing cyclical basis. On-bill or bill insert information would take approximately 10 days to prepare and begin to add to bills. Inserts would be added to bills throughout the month cycle.

1.3.6. Community Meetings

It is ENGLP's understanding that these meetings are no longer part of the hearing.

1.3.7. Publishing of Notice

ENGLP proposes that notices related to this Application appear in the Aylmer Express newspaper, as it is a prominent local publication, which is also available online at:

https://aylmerexpress.com/

1.3.8. Bill Impacts

This Application will impact all customers in ENGLP's Aylmer area of operations.

ENGLP is proposing in this application a segregated Rate 1 Rate Class (Rate 1 – Residential and Rate 1 – General Service).

As per the application, R1 Residential customers can expect a $38 (8%) increase in distribution charges resulting in a $78 (6%) total bill increase over a 12 month period.

R1 – General Service customers can expect a can expect a $126 (8%) increase in distribution charges over a 12 month period resulting in a $326 (6%) total bill increase over a 12 month period.

Further detail and bill impacts for all Rate Classes can be found in this Exhibit in section 1.5.8 along with Exhibit 8.

1.3.9. Customer Impacts

This Application will impact all customers in ENGLP's Aylmer area of operations.

1.3.10. Form of Hearing

ENGLP requests that, pursuant to Section 34.01 of the OEB's Rules of Practice and Procedure, this proceeding be conducted by way of written hearing.

1.3.11. Price Cap IR

ENGLP is proposing a five-year incentive rate-setting ("**IR**") plan, covering the period January 1, 2025 through to December 31, 2029. The proposed IR plan includes:

(a) an annual price cap adjustment based on two factors (an inflation factor ("I"), and a productivity factor + stretch factor (“X”));

(b) for Rate 1 (R1-Residential and R1-General Service, the fixed monthly charge would be increased annually by 15% (after the application of the PCA) and the volumetric charges would be correspondingly adjusted;

(c) a Y-factor for costs associated with specific items that are subject to deferral account treatment and passed through to customers without any Price Cap Adjustment;

(d) an Incremental Capital Module (“**ICM**”) to address the treatment of capital investment needs that arise;

(e) a Z-factor adjustment for unforeseen events outside of ENGLP’s management control; and,

(f) Continuance of the Earnings Sharing Mechanism, including the use of the Earnings Share Mechanism deferral account

(g) a trigger mechanism for a regulatory review in the event of a 300-basis point deviation from the Board approved return on equity (“**ROE**”).

1.3.12. Effective Date

ENGLP is requesting a rate effective date of January 1, 2025. In the event that the OEB is unable to provide a Decision and Rate Order in time for ENGLP to implement its rates effective January 1, 2025, ENGLP requests that the OEB declare current rates interim effective January 1, 2025 and approve rate riders to recover any change between current and approved revenue between the implementation date of the OEB’s 2025 Rate Order and January 1, 2025.

1.3.13. Rate Handbook Deviations

ENGLP confirms that it has not deviated from the filing requirements and Rate Handbook.

1.3.14. Methodology Changes

ENGLP is not proposing any changes to methodologies from its previous Application.

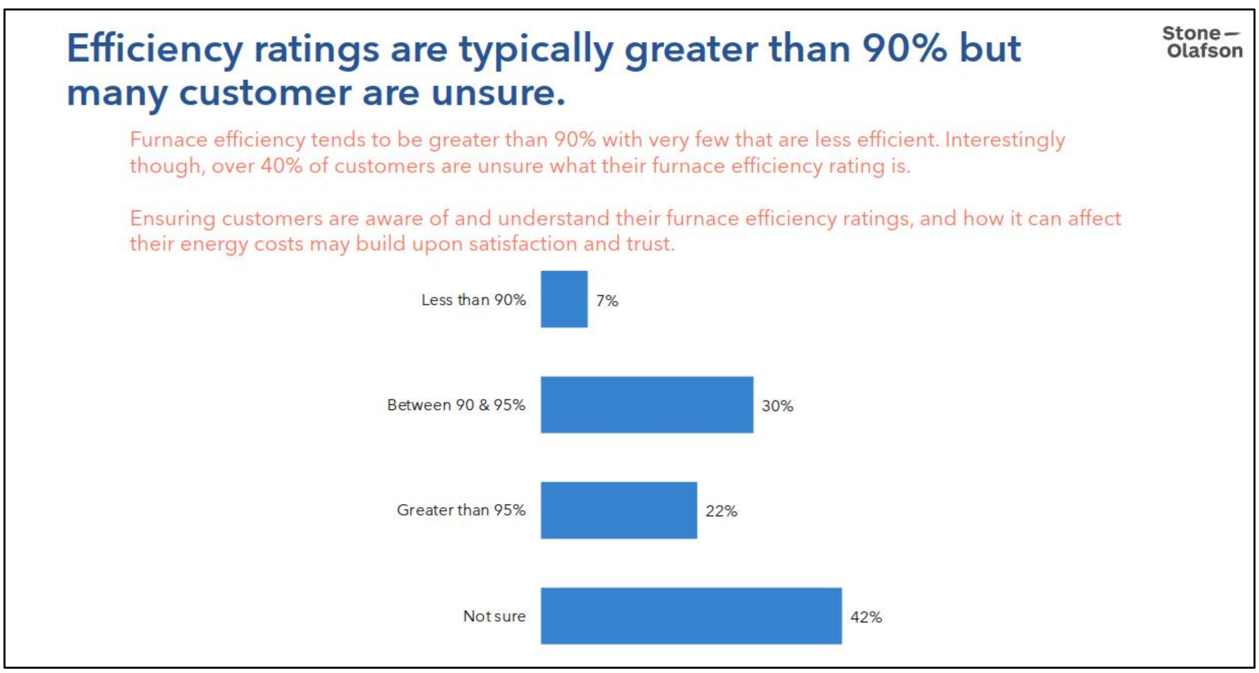
The projections for the 2025 Test Year were prepared in accordance with ENGLP’s budget process and all processes are in compliance with policies, directives and rules and guidelines from the OEB and other regulators.

1.3.15. OEB Directions from Previous Decision or Orders

In ENGLP's last cost of service proceeding (EB-2018-0336) (the "**2020 Rate Decision**"), the Board included two directives as set out below, which ENGLP has fulfilled. Accordingly, in the 2020 Rate Decision, dated July 4, 2019 at page 4, the OEB held:

> *The parties have also agreed under issue 3 b), which deals with volume throughput and revenue forecasts, that EPCOR Natural Gas will request further information from customers in order to update its volume forecasting. The OEB agrees that better customer information is helpful to the extent that EPCOR Natural Gas is able to get information voluntarily from customers.*

This customer information was requested a part of ENGLP's customer 2024 USP & customer engagement survey. The report of this survey can be found in Exhibit 2 in the Utility System Plan. ENGLP has begun obtaining furnace efficiency data through customer surveys, but does not yet have sufficient data to reflect changes in efficiency over time in the throughput forecast.



The OEB further held in the 2020 Rate Decision that:

> *For issue 8 a), parties have agreed to an earnings sharing mechanism (ESM)*

> *based on actual regulated net income over the term 2020 to 2024, taking into account any necessary adjustments. The OEB agrees with the ESM, but would find it helpful for future proceedings to clarify now the nature of the necessary adjustments. The OEB asks that the parties file a letter with the OEB clarifying the types of adjustments that are expected to be made to actual net income.*

This response was provided as part of EB-2018-0336 on July 19, 2019.

At the date of this submission, ENGLP is not aware of any additional OEB Directives from any previous OEB Decisions and/or Orders that require addressing in this Application.

1.3.16. Conditions of Service

ENGLP's current version of its Conditions of Service can be found on its website:

https://www.epcor.com/products-services/natural-gas/Pages/terms-and-conditions.aspx

ENGLP's Conditions of Service were last updated in January 2020, in alignment with the previous cost of service filing (EB-2018-0336). ENGLP has included updates to its Conditions of Service as part of this application. The proposed changes are largely clerical. For example, introducing a toll free phone number and removing specific dollar values that may change (instead pointing to the approved rate order). Conditions of Service Confirmation.

A detailed list of these changes along with a copy of the proposed Conditions of Services which includes the changes has been included in Exhibit 8 (Section 8.3) along with Exhibit 8, Appendix A.

The proposed changes are largely clerical. For example, introducing a toll free phone number and removing specific dollar values that may change (instead pointing to the approved rate order).

1.3.17. Conditions of Service Confirmation.

ENGLP confirms that there are no rates or charges listed in the Conditions of Service or other policies and regulations that are not included in ENGLP's approved rate schedules.

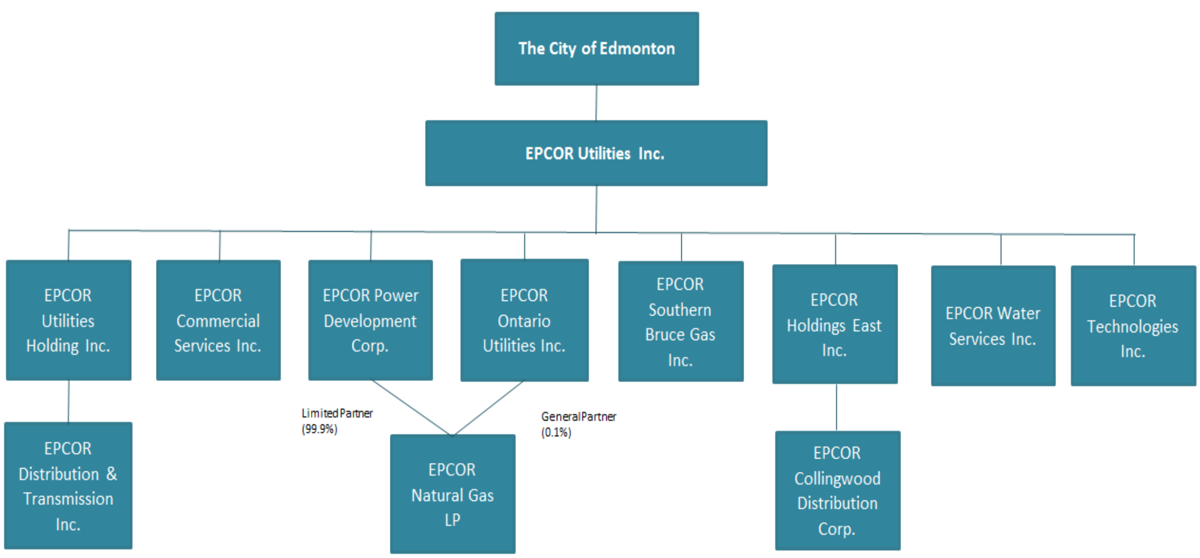
1.3.18. Organizational Structure

EPCOR is a gas distributor and is formed under the laws of the Province of Ontario, with offices in the Town of Aylmer and the Municipality of Kincardine. EPCOR is a wholly-owned indirect subsidiary of EUI. The general partner of EPCOR is EPCOR Ontario Utilities Inc., and the sole limited partner is EPCOR Commercial Services Inc., which are both subsidiaries of EUI.

EUI was incorporated as Edmonton Power Corporation pursuant to the *Business Corporations Act* (Alberta) on August 28, 1995. On May 8, 1996, Edmonton Power Corporation changed its name to EPCOR Utilities Inc. and, on May 26, 1999, the Corporation amended its Articles of Incorporation to delete the provision restricting the Corporation from offering its securities to the public. The City of Edmonton (the "**City"** or the "**Shareholder"**) is the sole common shareholder of the Corporation.

Figure 1.3.18-1

Simplified EPCOR Organizational Chart



ENGLP's Board (via the general partner EOUI) is represented by Directors who are two senior employees of EUI, along with one Director who is independent of EUI. This composition meets the requirements of Section 2.1.2 of the *Affiliate Relationships Code for Electricity Distributors* *and Transmitters*.

ENGLP does not currently have any changes in corporate or operational structure, including any changes in legal organization and control planned.

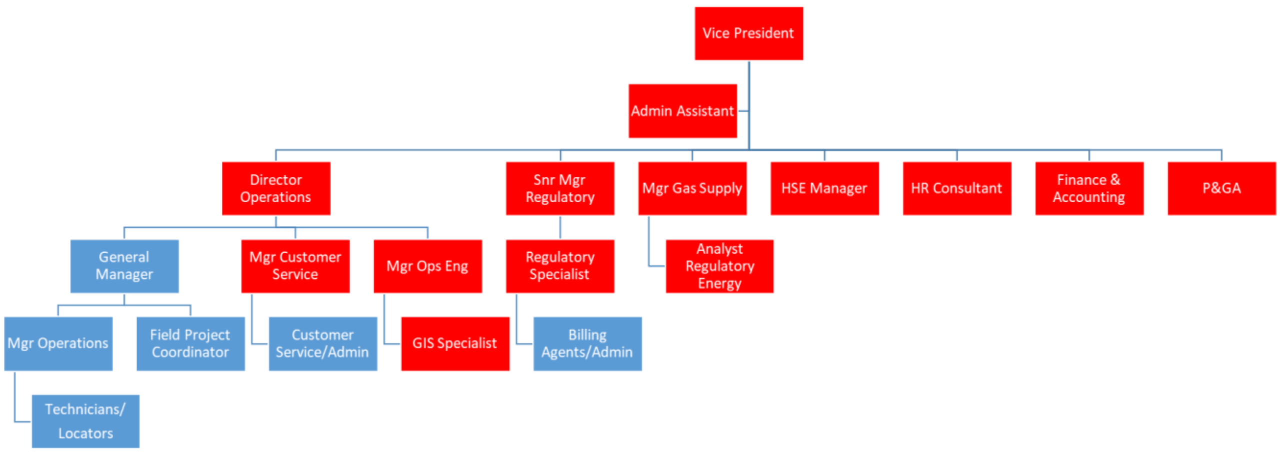
ENGLP employs 15 people in its Aylmer operations to ensure the safe and reliable operations of the distribution system and has maintained a consistent level of headcount in the last five years. This includes the General Manager, 2 Operations Managers, 10 Gas Technicians, 1 Quality Assurance/Locator, 8 Finance & Administration (Billing, Collections, Customer Service and Dispatch) and supporting management. Figure 1.3.18-2 details the organizational structures, presenting a view of embedded employees along with an expanded view, which includes affiliate services provided by supporting entities.

Certain ENGLP employees support both the Aylmer and Southern Bruce customers, with seven additional employees fully dedicated to supporting Southern Bruce. To help maintain lower operating costs, several of these employees split their time between the two organizations. This section is expanded further in Exhibit 4.3.3.1.

The figure below illustrates ENGLP's organizational structure, including affiliate employees.

Figure 1.3.18-2

ENGLP Organizational Structure (Embedded Employees and Affiliate Services)



ENGLP is also requesting approval for 2.5 additional FTE as part of this application which includes an additional locator technician (1 FTE planned in 2024 and 1 additional planned in 2025, along with 0.5 FTE of HSE support). Additional information can be found in Exhibit 4.

1.3.19. Requested Approvals and Accounting Orders

ENGLP hereby applies to the OEB, pursuant to section 36 of the *Ontario Energy Board Act*, 1998 as amended (the "**OEB Act**"), for an Order(s) approving its proposed natural gas distribution rates and other charges, effective January 1, 2025. Specifically, ENGLP applies for:

i. Approval of ENGLP's forecasted 2025 Test Year service revenue requirement of $8,048,058 and base revenue requirement of $7,939,670;

ii. Approval to charge distribution rates effective January 1, 2025 to recover a base revenue requirement and revenue deficiency, as detailed in the Revenue Requirement Work Form and discussed in Exhibit 6, through applying the proposed rates as set out in the Tariff Schedule & Bill Impact model and Exhibit 8;

iii. Approval of the Utility System Plan as outlined in Exhibit 2;

iv. Approval of the Working Capital Allowance as outlined in Exhibit 2;

v. Approval of Transportation Rates as proposed in Exhibit 8;

vi. Approval of the proposed Unaccounted for Gas Factor as detailed in Exhibit 8 and calculated;

vii. Approval of the Rate Riders for a 12-month disposition of the Purchased Gas Transportation Variance Account ("**PGTVA**") and Unaccounted for Gas ("**UFG**") and Variance account balances as at December 31, 2023 along with the projected carrying charges as detailed in Exhibit 9;

viii. Approval of the continued usage of the following related deferral and variance accounts (in addition to currently approved accounts related to the QRAM and Federal Carbon Pricing Plan applications):

1. Unaccounted For Gas Variance Account;
2. Regulatory Expense Deferral Account;
3. Purchased Gas Transportation Variance Account Rates 1-5;
4. Approved Deferral/Variance Disposal Account;

5. Earnings Share Mechanism Deferral Account;
6. Transportation Service Charge Deferral Account;
7. Accelerated CCA Income Taxes Variance Account;
8. LEAP EFA Funding Deferral Account;
9. Cloud Computing DVA and
10. Getting Ontario Connected Act Variance Account.

ix. Approval of proposed revisions to the PGTVA Rates 1-5, Regulatory Expense Deferral Account and Earnings Share Mechanism accounting orders as detailed in Exhibit 1.5.9.

x. ENGLP is proposing the following deferral and variance accounts be closed and discontinued from use:

1. Loss on Disposal of Meters Deferral Account; and
2. 2016-2017 System Integrity Capital Projects Deferral Account.

xi. Approval of Changes to the utility's Conditions of Service as detailed in Exhibit 8.

xii. Approval of the Customer Connection Policy included in Exhibit 2

1.3.20. Draft Issues List

The issues list proposed is based on the approved issues list of EB-2018-0336, updated as appropriate.

Issue 1 Administration

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

(b) Are the proposed changes to ENGLP's Conditions of Service appropriate?

Issue 2 Rate Base

(a) Were amounts closed (or proposed to be closed) to rate base since the utility's last rate proceeding in EB-2018-0336 and EB-2019-0276 prudently incurred?

(b) Is the level of planned capital expenditures 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.

(c) Is the working capital allowance for the 2025 Test Year appropriate?

Issue 3 Operating Revenue

(a) Are the customer addition forecasts for the 2024 Bridge Year and 2025 Test Year appropriate?

(b) Are the volume throughput and revenue forecasts for the 2024 Bridge Year and 2025 Test Year appropriate?

(c) Are the proposed Other Revenues for the 2025 Test Year appropriate?

Issue 4 Operating Costs

(a) 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.

(b) Are the depreciation costs for the 2025 Test Year appropriate?

(c) 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?

(d) Is the gas transportation cost forecast for the 2025 Test Year appropriate?

Issue 5 Deferral and Variance Accounts

(a) 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?

Issue 6 Cost of Capital

(a) Is ENGLP's proposed capital structure of 60% debt (56% long-term and 4% short-term) and 40% equity appropriate?

(b) Is ENGLP's cost of capital for the 2025 Test Year appropriate?

Issue 7 Cost Allocation and Rate Design

(a) Are the proposed changes to cost allocation, rate design and revenue-to-cost ratios appropriate?

(b) Are the proposed rates appropriate?

(c) Are ENGLP's Schedule of Service Charges appropriate?

Issue 8 Incentive Regulation Plan

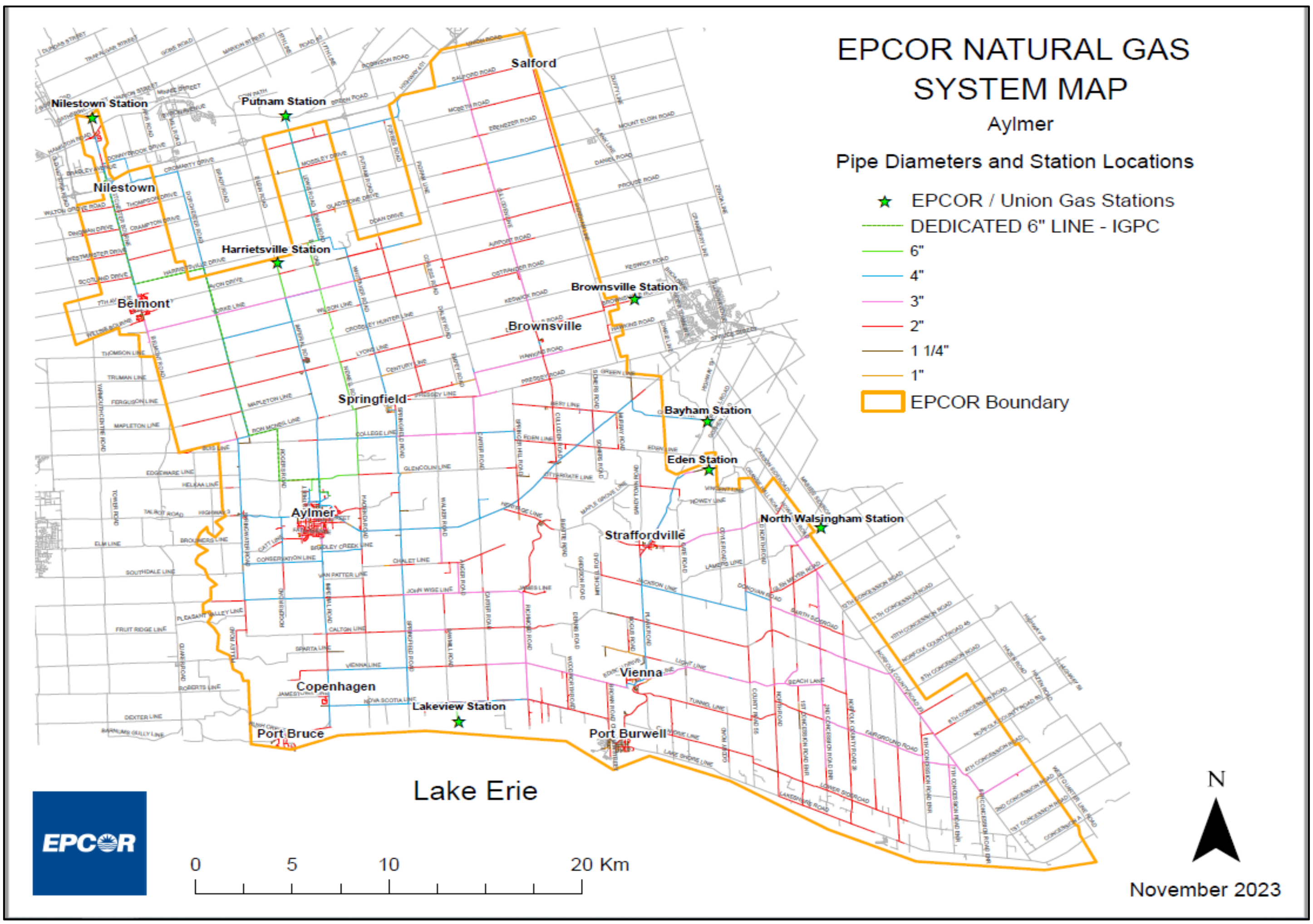
(a) Is ENGLP's proposed Incentive Regulation Plan for the period 2026 to 2029 appropriate?

Issue 9 Score Card

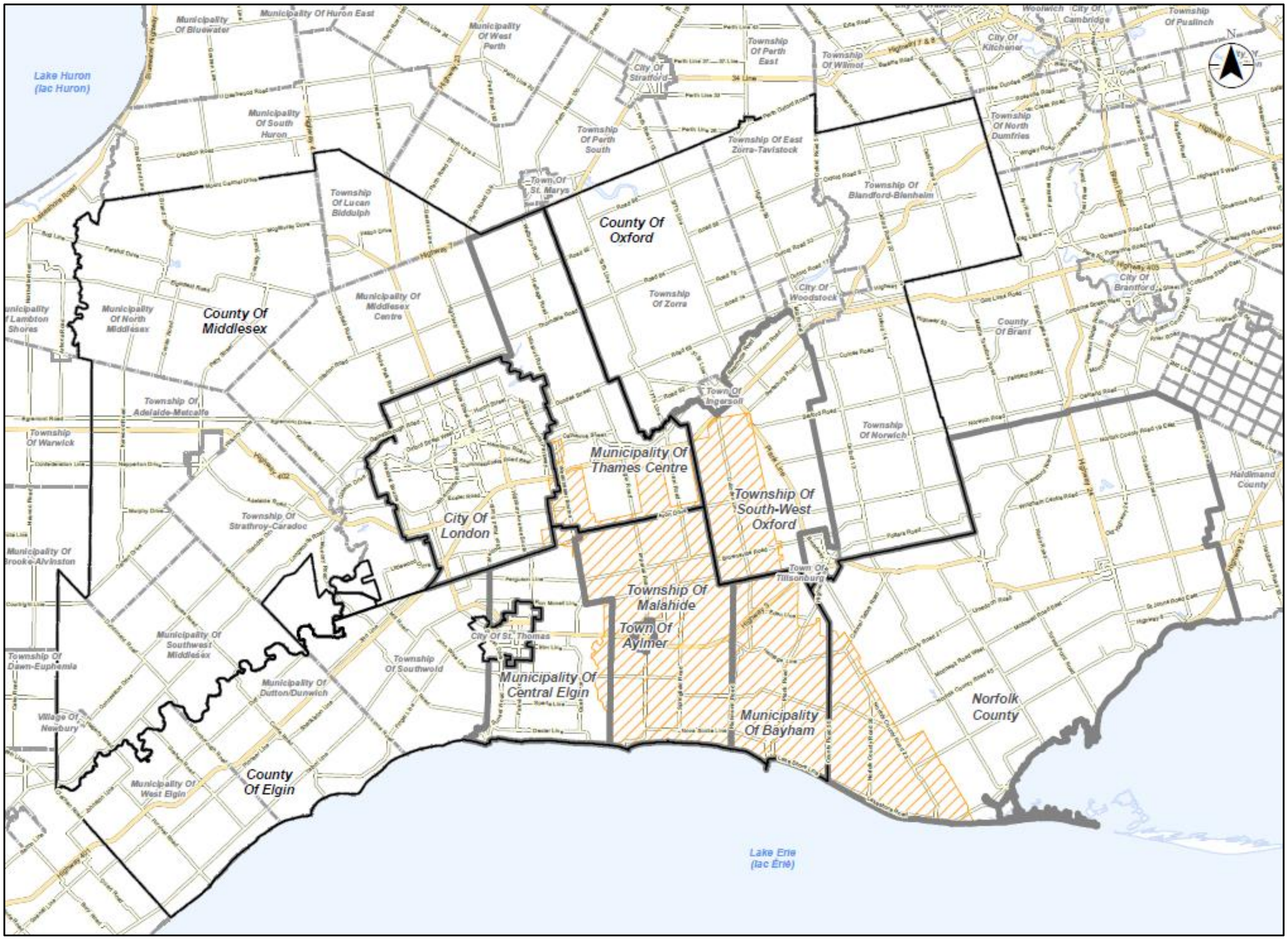
(a) Is ENGLP's proposed Score Card appropriate?

1.4. System Overview

ENGLP distributes natural gas to customers in and around Aylmer, Ontario, with its service area stretching from south of Highway 401 to the shores of Lake Erie, from Port Bruce in the west to Clear Creek in the east. It provides natural gas service to customers in Townships of Malahide and South-West Oxford; Municipalities of Bayham, Thames Centre and Central Elgin; and Norfolk County. The system serves the individual communities of Aylmer, Belmont, Brownsville, Port Burwell, Springfield, Straffordville, and Vienna. A map of the system is shown below:



ENGLP holds franchises for areas south-east of London which includes the towns of Aylmer, Belmont, Brownsville, Port Burwell, Springfield, Straffordville, and Vienna. A map showing ENGLP's franchise areas shown below.



ENGLP's Aylmer distribution system was first commissioned in the 1970's and has expanded to currently consist of approximately 920 kilometers of distribution mains (including a 6 inch high pressure steel line), all of which are fed by Enbridge (formerly Union Gas) gate stations and 38 gas wells. There are seven main metering and regulating stations throughout the system, one at each of the Enbridge custody transfer points: Nilestown Station, Harrietsville Station, Putnam Station, Brownsville Station, Bayham Station, Eden Station, and North Walsingham Station. In addition, Lagasco Inc. ("**Lagasco**") provides lake gas as a supply source through the Lakeview

Station within the southern part of the distribution system. Smaller regulating and control stations are distributed throughout the system. ENGLP also receives a supply of Renewable Natural Gas (“**RNG**”) from a facility in its service territory.

The gas demands in the ENGLP System are mainly for residential and commercial heating, small industrial users, and grain drying. The residential and commercial heating demand occurs during the winter months, the small industrial users include heating, which means that they peak in the winter, while the grain drying demand usually occurs in autumn or winter, but can occur at any time. Additionally, a 30 km dedicated 6-inch steel pipeline operating at a higher pressure feeds the largest industrial customer, IGPC. A pressure regulating and metering station is located on the downstream end of this pipeline. In 2024 ENGLP also connected a large agricultural customer in Phase 1 of an expansion with additional expansion being planned for 2024-2025.

Below is the ENGLP (Aylmer) summary of managed assets, which includes pipe diameters and station locations and map of ENGLP (Aylmer) service area:

	Facility	**Approximate Length (km)**	**Description**
Pipelines	IGPC Pipeline	29	Steel NPS 6”
	Community Distribution Piping	32	MDPE NPS 6”
	Community Distribution Piping	860	MDPE NPS 1 ¼”, 2”, 3” & 4”
	Services	345	MDPE NPS ½”, 1”, 1 ¼”& 2”, 4”
	Main Line Valves	225	
District Stations	District Stations	14	
Metering Stations	**Facility**	**Description**	
	Lakeview	Pressure Regulating and Metering Station	
	Putnam	Pressure Regulating and Metering Station	
	Harrietsville	Pressure Regulating and Metering Station	
	North Walsingham	Pressure Regulating and Metering Station	
	Bayham	Pressure Regulating and Metering Station	
	Eden	Pressure Regulating and Metering Station	
	Brownsville (Delmer)	Pressure Regulating and Metering Station	
	North Belmont (Nilestown)	Pressure Regulating and Metering Station	

1.5. Application Summary

1.5.1. Revenue Requirement

Refer to Exhibit 6 – Revenue Requirement for further detail and analysis.

ENGLP is proposing a service revenue requirement for the 2025 Test Year of $8,048,058. The revenue requirement reflects an increase of $2,321,979 or 41% from the $5,726,079 approved in 2020 (EB-2018-0336, excluding Transportation revenue). This represents an annual increase of approximately 8%. Customer impacts have been mitigated due to a 7% increase in customer count and a 17% increase in projected consumption since the last rebasing.

Table 1.5-1 below highlights the main drivers of revenue requirement and the change from the previous cost of service application.

Note, as further explained in this Exhibit and Application, ENGLP is proposing to remove the Transportation Revenue/Costs from the Distribution Revenue Requirement (which are currently embedded in a reference price). These amounts have been isolated for comparison purposes.

Table 1.5.1-1

Summary of Changes in Revenue Requirement ($)

Driver	2020T	2025T	Variance ($)	*Variance (%)*	*Annual Variance (%)*
OM&A	$3,209,102	$4,321,958	$1,112,856	34.7%	6.9%
Depreciation	$876,563	$1,320,799	$444,236	50.7%	10.1%
Property Taxes	$632,000	$705,564	$73,564	11.6%	2.3%
Income Taxes	$61,842	$74,989	$13,147	21.3%	4.3%
Cost of Debt	$366,432	$643,825	$277,393	75.7%	15.1%
Return on Equity	$580,140	$980,922	$400,782	69.1%	13.8%
Service Revenue Requirement	**$5,726,079**	**$8,048,058**	**$2,321,979**	**40.6%**	**8.1%**
Revenue Offsets	*($147,778)*	*($108,388)*	*$39,390*	*-27%*	*-5%*
Dist Revenue Requirement	**$5,578,301**	**$7,939,670**	**$2,361,369**	**42.3%**	**8.5%**

The variance is driven by an increase of $1,112,856 in OM&A costs which reflect general inflation of approximately 17%, an increase in customers serviced of approximately 7% and additional FTE required to meet government legislation on locates. The increase in depreciation is driven by an increase in the proposed rate base of 65% (additional asset investment driven by customer growth, increased construction standards and cost inflation).

The increase in cost of capital (cost of debt and equity) is driven by the increase in rate base along with an increase in the weighted average cost of capital of 0.24% (increasing from 5.86% to 6.10%) driven by higher interest rates.

Table 1.5.1-2 below compares the previous test year, increased by inflation in comparison to the proposed revenue requirement. '2020T Inflation' is calculated using the 2020T test year amounts escalated by the inflationary factors approved in ENGLP's IRM filings, along with a 3.5% 2025 forecast value.

Table 1.5.1-2

Summary of Changes in Revenue Requirement ($)

Driver	2020T Inflation	2025T	Variance ($)	*Variance (%)*
OM&A	$3,752,216	$4,321,958	$569,742	15.2%
Depreciation	$1,024,914	$1,320,799	$295,885	28.9%
Property Taxes	$738,961	$705,564	($33,397)	-4.5%
Income Taxes	$72,308	$74,989	$2,681	3.7%
Cost of Capital	$428,447	$643,825	$215,377	50.3%
Return on Equity	$678,324	$980,922	$302,598	44.6%
Service Revenue Requirement	**$6,695,171**	**$8,048,058**	**$1,352,887**	**20.2%**
Revenue Offsets	*($147,778)*	*($108,388)*	*$39,390*	*-27%*
Dist Revenue Requirement	**$6,547,393**	**$7,939,670**	**$1,392,277**	**21.3%**

1.5.2. Throughput Forecast Summary

Refer to Exhibit 3 – Operating Revenue & ENGLP's 2024-2028 gas supply plan (EB-2014-0139)

ENGLP engaged Power Advisory LLC ("**Power Advisory**") to complete the 2025 Test Year load forecast. Power Advisory provided forecasts by rate class for consumption and demand (if applicable) and the number of customers and connections. The sales and energy forecast utilized actual data from January 2012 to December 2023.

ENGLP has also filed a Gas Supply Plan (EB-2024-0139), which has been used as the basis for preparation of the volume and customer count forecast used in this Application.

Methodology:

The forecasted annual customer service demand for R1 Residential, R1 Commercial, R1 Industrial and R3 rate classes were determined through multivariate regressions. Consumption of the three R1 rate classes were forecasted using a base load and excess consumption methodology wherein average monthly consumption per customer was first calculated for each class. The amounts were then reduced by the base load consumption, which is considered the average consumption in the summer months of July and August. The remaining consumption is considered the weather-sensitive load (or "excess" load).

The excess load was regressed by the actual heating degree days in each month to determine the impact of cold weather on average consumption. A time-series (Prais-Winsten) regression was used to determine the coefficient, consistent with the methodology used in prior ENGLP/NRG throughput forecasts. Actual heating degree days were then multiplied by the coefficients and base load consumption was added back to determine the average predicted consumption in each month. Predicted total consumption of a class was determined by multiplying this sum by the actual number of customers. Similar methodology was used for the R3 rate class; however, the base load was not removed from the regression.

Consumption of the remaining four rate classes (R2 Seasonal, R4, R5 and R6) were not weather-sensitive and did not exhibit sensitivity to the explanatory variables. Total and monthly volumes fluctuate from year-to-year and as such, a five-year rolling average was used to forecast monthly consumption for each of these classes, with the exception of R4 in which a trend is also applied.

The customer connections count was forecasted by applying the geometric mean annual growth rate from 2012 to 2023 to the 2023 average customer count.

The forecasted change in mid-year customer count from 2020-2025 is detailed below in Table 1.5.2-1.

Table 1.5.2-1 - Load Forecast Summary

Volumes

(000's m^3)	2020T	2025T	Variance	Variance %
R1 Residential	17,046	19,778	2,733	16%
R1 Commercial	4,852	6,194	1,342	28%
R1 Industrial	1,743	2,686	943	54%
R2 Seasonal	1,280	832	(448)	-35%
R3	1,722	3,918	2,196	128%
R4	1,149	2,335	1,186	103%
R5	686	648	(38)	-6%
R6	59,244	65,346	6,102	10%
Total	**87,721**	**101,737**	**14,016**	16%

Customers

Count	2020T	2025T	Variance	Variance %
R1 Residential	9,011	9,578	567	6%
R1 Commercial	498	590	92	18%
R1 Industrial	69	81	12	17%
R2 Seasonal	49	50	1	2%
R3	6	5	(1)	-17%
R4	38	46	8	21%
R5	4	4	0	0%
R6	1	1	0	0%
Total	**9,676**	**10,355**	**679**	7%

*Note that ENGLP has included a proposal to separate Rate 1 into Residential and General Service categories, but the Load Forecast was completed using the legacy Rate 1 setup and presentation of three distinct groups for Rate 1 (Residential/Commercial/Industrial).

1.5.3. Rate Base and Utility System Plan (USP)

Refer to Exhibit 2 – Rate Base and USP for further detail and analysis.

ENGLP requires prudent capital investments and maintenance plans to ensure the reliability and sustainability of its distribution network. ENGLP operates with a high level of reliability and strives to provide consistent and dependable service to its natural gas customers. This is a direct outcome of its asset class objectives, strategies and investment planning processes as described in the Asset Management Plan and USP.

ENGLP's USP documents the practices, policies and processes that are in-place to ensure that decisions on capital investments and maintenance plans support ENGLP's desired outcomes in a cost-effective manner and provides value to the customer. As part of its planning process, ENGLP has aimed for a consistent capital budget envelope for the USP period that balances investments through a project pacing and prioritization process.

ENGLP establishes the requirements and estimates the related capital investment needs in accordance with its Asset Plan. The main drivers include:

- Capital investments related to customer growth identified through the asset planning and gas supply planning process;
- Capital investments related to reinforcement projects to maintain system pressure, capacity and meet growth demands;
- Capital investments related to maintaining and enhancing the safety and reliability of ENGLP assets and to ensure compliance with relevant codes and regulations;
- Capital investments related to replacement of plant, vehicles, equipment, computer hardware and software, as a result of age and condition; and,
- Capital investments related to any new programs and initiatives.

Investment projects and activities have been grouped into one of the four general investment categories outlined in the Filing Requirements for Natural Gas Rate Applications, based on the driver of the expenditure. The description of each investment category is as follows:

a) **System Access** investments are modifications to the distribution system to provide a new customer or group of customers with access to natural gas service via the distribution system. This includes the relocation of distribution assets to accommodate infrastructure development or modifications by a municipal or provincial authority, or other third-party (e.g. modifications to a highway interchange);

b) **System Renewal** investments involve replacing and/or refurbishing system assets to extend the original service life of the assets and ensure system integrity, thereby, maintaining the ability of ENGLP's distribution system to provide customers with natural gas services;

c) **System Service** investments are modifications to ENGLP's distribution system to improve reliability, mitigate risk or introduce efficiencies while addressing anticipated future customer gas service requirements

d) **General Plant** investments are additions, modifications or replacements of assets used to support business, operations and maintenance activities but not part of the distribution system, including land and buildings, fleet vehicles, tools and equipment, electronic devices and software.

ENGLP's Application includes a forecasted rate base of $26.627M for the 2025 Test Year. This represents an increase of $10.467M from the $16.160M approved rate base in the previous rate Application.

ENGLP's Application also includes a request for a working capital allowance, consistent with guidance provided to electricity distributors.

The following table details both the derivation of respective rate bases and a summary of the proposed rate base.

Table 1.5.3-1
Summary of Changes in Rate Base
($000's)

	2020T Test	2025T Test	Variance $	Variance %
Opening Balance, January 1	$16,042	$24,181	$8,139	51%
Closing Balance, December 31	$16,277	$26,925	$10,648	65%
Net Fixed Assets (average)	$16,160	$25,553	**$9,393**	**58%**
Controllable Expenses	$3,359	$4,322	$963	29%
Cost of Gas (Non-Distribution)	N/A	$9,992		
Working Capital Base	N/A	$14,314		
Working Capital Rate %	0.00%	7.50%	7.50%	
Working Capital Allowance	$0	$1,074	**$1,074**	
Total Rate Base	**$16,160**	**$26,627**	**$10,467**	**65%**

ENGLP is proposing a capital plan for the 2025 Test Year of $4.064M. This is a $2.724M increase from the $1.340M capital plan previously approved for 2020. Proposed Expenditures by type, including System Access, System Renewal, System Service and General Plant are as in Table 1.2-4 below. The Distribution System Plan included in Exhibit 2 provides additional details on ENGLP's proposed capital plan.

Table 1.5.3-2
Proposed 2025 Test Year Capital Expenditures and 2013 Board Approved
($000's)

($000's)	**2020T**	**2025T**	**Var ($)**	**Var %**
System Access	$523	$1,954	$1,431	274%
System Renewal	$490	$1,460	$970	198%
System Service	$269	$450	$181	67%
General Plant	$130	$272	$142	109%
Total Expenditure	**$1,412**	**$4,136**	**$2,724**	**193%**
Capital Contributions	$72	$72	$0	0%
Net	**$1,340**	**$4,064**	**$2,724**	**203%**

1.5.4. Operations, Maintenance and Administration Expense (OM&A)

Refer to Exhibit 4 – Operating Expenses for further detail and analysis.

ENGLP's 2025 Test Year OM&A costs are forecast to be $4,321,958, which represents an increase of $1,112,856 from the 2020 Board Approved amount, or equivalent to an increase at an annualized rate of 6.9%.

Table 1.5.4-1 Proposed 2025 Test Year OM&A Expenditures and 2020 Board Approved ($)

Driver	2020T	2025T	Variance ($)	*Variance (%)*	*Annual Variance (%)*
Staffing Costs	$1,432,123	$1,335,560	($96,563)	-6.7%	-1.3%
Affiliate Services	$453,505	$1,085,178	$631,673	139.3%	27.9%
Corporate Shared Services	$439,217	$580,203	$140,986	32.1%	6.4%
Audit Fees	$31,334	$28,161	($3,173)	-10.1%	-2.0%
Contractors and Consultants	$315,035	$329,701	$14,666	4.7%	0.9%
Regulatory Costs	$211,852	$139,000	($72,852)	-34.4%	-6.9%
Legal Fees	$34,468	$35,735	$1,267	3.7%	0.7%
Bad Debts	$34,200	$97,066	$62,866	183.8%	36.8%
Other	$257,368	$691,354	$433,986	168.6%	33.7%
Total	**$3,209,102**	**$4,321,958**	**$1,112,856**	**34.7%**	**6.9%**

The overall increase from 2020 to 2025 can be attributed to several factors, including:

- Approximately $500K due to cost inflation; and
- An increase in FTEs required to keep up with increasing community growth (i.e. new connections and legislated locate requirements) and utility operating maturity (5 years of hands on experience running the utility).

ENGLP believes that the proposed costs for the 2025 Test Year reflect the minimum cost required to operate the utility in a manner that provides the level of service expected by customers while maintaining safe, reliable, and efficient operations. ENGLP will continue to seek cost savings and efficiencies to minimize the impacts to ratepayers. The proposed OM&A costs for the 2023 Test Year are aligned with ENGLP's expectations for annual costs going forward.

ENGLP's integrity management strategy is to minimize reactive and emergency-type work through efficient operations and an effective planned maintenance program, including predictive and preventative actions. ENGLP has a combined inspection and maintenance practice for field assets which is designed to optimize and extend the asset lifecycle until such time that the asset has reached a condition requiring refurbishment or replacement prior to any incidents.

1.5.5. Cost of Capital

Refer to Exhibit 5 – Cost of Capital and Capital Structure for further detail and analysis.

ENGLP has submitted cost of capital evidence in Exhibit 5 of this Application consistent with the *Report of the Board on Cost of Capital for Ontario's Regulated Utilities* issued December 11, 2009. No deviations from the Board's cost of capital methodology are contemplated.

Table 1.5.5-1 below identifies the weighted average cost of capital proposed for the 2025 Test Year as well as the rates of return respective of short-term debt and equity. ENGLP understands that these rates will be updated once the 2025 cost of capital parameters are issued by the Board.

ENGLP's long-term debt has been calculated based on affiliate debt issuances , which has been calculated incorporating a top-down internal credit analysis.

Table 1.5.5-1

Weighted Average Cost of Capital

	Capital Component	A **Ratio**	B **Cost Rate**	C **Return Component (WACC)**
1	Equity	40%	9.21%	3.68%
2	Long-term Debt	56%	3.87%	2.17%
3	Short-term Debt	4%	6.23%	0.25%
4	**Total**	**100%**		**6.10%**

1.5.6. Cost Allocation and Rate Design

Refer to Exhibit 7 – Cost Allocation for further detail and analysis.

The cost allocation study (the "Study") detailed in Exhibit 7 apportions the proposed 2025 Test Year rate base and revenue requirement for ENGLP's Aylmer business unit to each of the existing seven customer rate classes. An Excel version of the Study has been included with this submission (ENGLP_EB-2024-0130_Cost Allocation).

The results of the Study are summarized in the table below including the forecasted revenues, cost of service allocation, and revenue to cost ratio for each customer class. As shown in Table 7.1-1 below, the revenue to cost ratios for Rate 1 Residential, R1 General Service, Rate 3, Rate 5, and Rate 6 are within a range of plus or minus 20%. The revenue to cost ratio for Rate 2 rate is slightly below the threshold at 0.797 and the ratio for Rate 4 is below the threshold at 0.781.

Table 1.5.6-1 Cost Allocation

(Distribution & Other Revenue) ($)

		A Total	B Rate 1 - Residential	C = D + E Rate 1 - General Service	*D* *R1* *Commercial*	*E* *R1* *Industrial*	F Rate 2	G Rate 3	H Rate 4	I Rate 5	J Rate 6
1	Proposed Revenue	8,048,058	5,197,277	1,207,978	889,304	318,674	103,851	293,607	296,409	54,947	893,989
2	Cost	8,048,058	5,108,217	1,139,513	910,940	228,573	130,312	315,727	379,521	46,271	928,497
3	Over (Under) Contribution	0	89,060	68,465	-21,636	90,101	-26,461	-22,120	-83,112	8,676	-34,509
4	**Revenue to Cost Ratio**	**1.00**	**1.02**	**1.06**	**0.98**	**1.39**	**0.797**	**0.93**	**0.78**	**1.19**	**0.96**
5	EB-2018-0336 (July 4, 2019 Interim Decision)	1.00	0.98	0.99	0.98	1.03	1.01	0.97	0.93	0.64	1.06

ENGLP has applied accepted cost allocation principles and used a three-step methodology of functionalization, classification and allocation of the costs to provide service. The Study categorizes all costs into functional areas (gas supply, distribution related, customer and administrative) which are then classified as being commodity, demand, or customer related. These three major cost components are then allocated to the proposed customer rate classes based on allocation factors derived from basic customer data.

This Study uses a methodology that is consistent with the last two cost allocation studies approved by the Board for 2020 rates (EB-2018-0336) and 2011 rates (EB-2010-0018).

1.5.7. Performance and Reporting

ENGLP has included a copy of its scorecard in Section 1.7 of this Exhibit. Additional information can also be found in Exhibit 2.2.7. Throughout this 5 year term, ENGLP has maintained or exceeded standards of its scorecard.

ENGLP is not proposing any adjustments to this scorecard in this application.

1.5.8. Bill Impacts

Refer to Exhibit 8 – Rate Design for further detail and analysis.

The Bill Impacts per rate class are presented below, including the bottom 10 percentile for Rate 1 customers (along with the Top 10 percentile for the newly created R1-General Service rate).

Rate Class	Change in Delivery Charge ($ / year / customer)	Change in Delivery Charge (%)	Change in Transportation ($ / year / customer)	Change in Transportation (%)	Change in Rate Riders ($ / year / customer)	Change in Rate Riders (%)	Change in Total Bill ($ / year / customer)	Change in Total Bill (%)
R1 - Residential	**$38**	**8%**	**$10**	**21%**	**$29**	**180%**	**$78**	**6%**
R1 - Residential - Bottom 10 %	**$41**	**12%**	**$3**	**21%**	**$8**	**170%**	**$52**	**10%**
R1- General Service	**$126**	**8%**	**$53**	**21%**	**$148**	**183%**	**$326**	**6%**
R1-GS - Commercial	***$106***	***8%***	***$53***	***21%***	***$148***	***183%***	***$307***	***6%***
R1-GS - Commercial - Bottom 10 %	***$39***	***12%***	***$2***	***21%***	***$7***	***167%***	***$48***	***10%***
R1-GS - Commercial - Top 10 %	***$400***	***7%***	***$262***	***21%***	***$741***	***184%***	***$1,403***	***6%***
R1-GS - Industrial	***$266***	***7%***	***$166***	***21%***	***$469***	***184%***	***$900***	***6%***
R1-GS - Industrial - Bottom 10 %	***$46***	***10%***	***$8***	***21%***	***$22***	***178%***	***$76***	***8%***
R1-GS - Industrial - Top 10 %	***$980***	***8%***	***$667***	***21%***	***$1,885***	***184%***	***$3,532***	***6%***
R2 - Seasonal - Annual	**$155**	**8%**	**$83**	**21%**	**$277**	**216%**	**$515**	**7%**
R3 - Large Volume Contract	**$4,178**	**8%**	**$3,919**	**21%**	**$685**	**11%**	**$8,782**	**3%**
R4 - Peaking - Annual	**$615**	**10%**	**$254**	**21%**	**$611**	**156%**	**$1,479**	**6%**
R5 - Interruptible Peaking	**($925)**	**-7%**	**$810**	**21%**	**$3,479**	**279%**	**$3,364**	**5%**
R6 - IGPC	**$63,942**	**8%**	**$0**	**0%**	**($0)**	**-100%**	**$63,942**	**8%**

Delivery bill impacts vary by rate class due to the Cost Allocation process and the changes in transportation charges and rate riders are largely consumption driven as those values are calculated based on usage.

1.5.9. Deferral and Variance Accounts

Refer to Exhibit 9 – Deferral & Variance Accounts for further detail and analysis.

ENGLP is proposing to dispose of two deferral accounts in this filing. A summary of the treatment of all existing and proposed deferral accounts is included below.

Table 1.5.8-1

DVA Summary

Account	Short Name	Dec 31, 2023 Balance (incl. carrying charges to Dec 2024)	Disposition Proposal	Status	Previous Disposition Year
Current Accounts					
Unaccounted For Gas Variance Account	UFGVA	$527,094	Disposition	Continuance	N/A
Regulatory Expense Deferral Account	REDA	$322	No	Continuance	2022
Purchased Gas Transportation Variance Account Rates 1-5	PGTVA	$217,382	Disposition	Continuance	2022
Approved Deferral/Variance Disposal Account	ADVADA	$230,539	No	Continuance	2022
Earnings Share Mechanism Deferral Account	ESMDA	$0	N/A	Continuance	N/A
Transportation Service Charge Deferral Account	TSCDA	$0	N/A	Continuance	N/A
Accelerated CCA Income Taxes Variance Account	ACITVA	$0	N/A	Continuance	N/A
LEAP EFA Funding Deferral Account	LEAPDA	$0	N/A	Continuance	N/A
Cloud Computing DVA	CLOUDVA	$0	N/A	Continuance	N/A
Getting Ontario Connected Act Variance Account	LOCATEVA	$0	N/A	Continuance	N/A
Accounts to be Closed					
Loss on Disposal of Meters Deferral Account	LDMDA	$0	N/A	Closed	2021
2016-2017 System Integrity Capital Projects Deferral Account	SICDA	$0	N/A	Closed	2021
Excluded From This Application					
Customer Carbon Charge Variance Account	CCCVA	N/A	N/A	Continuance	
Facility Carbon Charge Variance Account	FCCVA	N/A	N/A	Continuance	
Greenhouse Gas Emissions Administration Deferral Account:	GGEADA	N/A	N/A	Continuance	
Purchased Gas Commodity Variance Account	PGCVA	N/A	N/A	Continuance	
Gas Purchase Rebalancing Account	GPRA	N/A	N/A	Continuance	

ENGLP is not proposing to add any new deferral and variance accounts as part of this application, but has proposed minor wording edits for three of the existing accounting orders (REDA/PGTVA 1-5/ESM). The proposed changes follow, and a list of all relevant accounting orders included in this application has been included in this Exhibit as Schedule 2.

Changes to Regulatory Expense Deferral Account

Current Wording:

To record the collection of the balance recorded in the account as of September 30, 2009 from REDA Rate Rider:

Credit Account No. 179-21 Regulatory Expense Deferral Account (REDA) by REDA Rate Rider to collect $172,801

Debit Account No. 140 Accounts Receivable - Customers

To record the collection of the balance of associated carrying charges as of September 30, 2009 from REDA Rate Rider:

Credit Account No. 179-22 Other Interest Expense by REDA Rate Rider to collect $1,106

Debit Account No. 140 Accounts Receivable - Customers

Proposed Wording: (remove entire section)

~~To record the collection of the balance recorded in the account as of September 30, 2009 from REDA Rate Rider:~~

~~Credit Account No. 179-21 Regulatory Expense Deferral Account (REDA) by REDA Rate Rider to collect $172,801~~

~~Debit Account No. 140 Accounts Receivable - Customers~~

~~To record the collection of the balance of associated carrying charges as of September 30, 2009 from REDA Rate Rider:~~

~~Credit Account No. 179-22 Other Interest Expense by REDA Rate Rider to collect $1,106~~

~~Debit Account No. 140 Accounts Receivable - Customers~~

Rationale:

Legacy wording, no longer relevant.

Changes to Purchased Gas Transportation Variance Account Rates 1-5:

Current Wording:

As the transportation costs are a flow-through to customers, EPCOR Natural Gas Limited Partnership ("ENGLP") has an established Purchased Gas Transportation Variance Account Rates 1-5 ("PGTVA 1-5") to record differences between forecasted transportation costs included in ENGLP's approved rates via the PGTVA reference price, and the actual transportation costs incurred by ENGLP. The PGTVA also records amounts related to deferral account dispositions received or invoiced from ENGLP's transportation suppliers.

Effective January 1, 2020 ENGLP is authorized to re-set the reference price for the PGTVA 1-5. The reference price of $0.023724/m^3$ will be applicable to all customers in rate classes 1 through5 To record the monthly difference between the reference price, and the actual transportation costs incurred by ENGLP under its M9 and Bundled T contracts with Enbridge Gas Inc. for the volumes required to serve the customers in rate classes 1-5:

Proposed Wording:

As the transportation costs are a flow-through to customers, EPCOR Natural Gas Limited Partnership ("ENGLP") has an established Purchased Gas Transportation Variance Account Rates 1-5 ("PGTVA 1-5") to record differences between forecasted transportation costs included in ENGLP's approved rates via ~~the PGTVA reference price~~ **the Transportation Rate**, and the actual transportation costs incurred by ENGLP. The PGTVA also records amounts related to deferral account dispositions received or invoiced from ENGLP's transportation suppliers.

~~Effective January 1, 2020 ENGLP is authorized to re-set the reference price for the PGTVA 1-5. The reference price of $0.023724/m3 will be applicable to all customers in rate classes 1 through 5.~~

To record the monthly difference between the ~~reference price~~ **Transportation Rate**, and the actual transportation costs incurred by ENGLP under its M9 and Bundled T contracts with Enbridge Gas Inc. for the volumes required to serve the customers in rate classes 1-5:

Rationale:

ENGLP has included a proposal in this application to create a stand-alone Transportation charge rather than an reference price embedded within distribution rates. The rate may change during the IR term, so the specific price is not required within the accounting order

Changes to Earnings Share Mechanism Deferral Account

Current Wording:

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") 2020-2024 distribution rate application EB-2018-0336. In the event that the utility's cumulative ROE from 2020 to 2024 exceeds the Board-approved ROE in EB-2018-0336 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 cumulative ROE will be calculated as the sum of actual regulated net income over the term, 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 cumulative 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.

For the purposes of calculating the utility's regulated net income for assessment under the ESM, ENGLP's annual Affiliate and Corporate Shared Services costs included in O&M costs as described in the original application for EB-2018-0336 shall be capped at the lower of a) actual costs incurred annually or b) the Affiliate and Corporate Shared Services costs included in the 2020 Test Year Board-approved revenue requirement per EB-2018-0336 as inflated annually by the inflation factors approved for use in ENGLP's annual IRM applications.

The audited balance in this account will be brought forward for approval for disposition after the end of the Price Cap IR Term, once cumulative earnings over the 2020-2024 term have been assessed and the actual ESM amount has been determined.

As any balance in this account is not owing until earnings over the entire 2020-2024 term are assessed as over-earned under the ESM, interest will not be computed on the balance in the ESMDA.

Proposed Wording:

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") ~~2020-2024~~ **2025-2029** distribution rate application ~~EB-2018- 0336~~ **EB-2024-0130**. In the event that the utility's cumulative ROE from ~~2020 to 2024~~ **2025-2029** exceeds the Board- approved ROE in ~~EB-2018- 0336~~ **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 cumulative ROE will be calculated as the sum of actual regulated net income over the term, 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 cumulative 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.

~~For the purposes of calculating the utility's regulated net income for assessment under the ESM, ENGLP's annual Affiliate and Corporate Shared Services costs included in O&M costs as described in the original application for EB-2018-0336 shall be capped at the lower of a) actual costs incurred annually or b) the Affiliate and Corporate Shared Services costs included in the 2020 Test Year Board-approved revenue requirement per EB-2018-0336 as inflated annually by the inflation factors approved for use in ENGLP's annual IRM applications.~~

The audited balance in this account will be brought forward for approval for disposition after the end of the Price Cap IR Term, once cumulative earnings over the ~~2020-2024~~ **2025-2029** term have been assessed and the actual ESM amount has been determined.

As any balance in this account is not owing until earnings over the entire ~~2020-2024~~ **2025-2029** term are assessed as over-earned under the ESM, interest will not be computed on the balance in the ESMDA.

Rationale: Removing wording specifically relevant to EB-2018-0336.

1.5.10. Incentive Rate-Setting Mechanism

ENGLP is proposing a five-year incentive rate-setting ("**IR**") plan, covering the period through December 31, 2029. The proposed IR plan includes:

an annual price cap adjustment based on two factors (an inflation factor ("I"), and a productivity factor + stretch factor ("X"));

(a) for Rate 1 (R1-Residential and R1-General Service, the fixed monthly charge would be increased annually by 15% (after the application of the PCA) and the volumetric charges would be correspondingly adjusted;

(b) a Y-factor for costs associated with specific items that are subject to deferral account treatment and passed through to customers without any Price Cap Adjustment;

(c) an Incremental Capital Module ("**ICM**") to address the treatment of capital investment needs that arise;

(d) a Z-factor adjustment for unforeseen events outside of ENGLP's management control; and,

(e) Continuance of the Earnings Sharing Mechanism, including the use of the Earnings Share Mechanism deferral account

(f) a trigger mechanism for a regulatory review in the event of a 300-basis point deviation from the Board approved return on equity ("**ROE**").

Additional detail of the proposed Price Cap IR method is included in Exhibit 10.

1.6. Customer Engagement

Since acquiring the utility in 2017, ENGLP has worked to communicate and engage with customers in its distribution area to ensure that customer service and capital investment is prudent, appropriate and aligns with community interests and priorities.

ENGLP engages customers and stakeholders every day, through phone calls, emails and in-person visits. Operations staff also engage with customers when connecting meters or providing service calls. ENGLP also tailors engagement to the needs of the topic and the community. It engages with customers and communicates about education, safety, system reliability, billing and its community presence. ENGLP is committed to open, transparent communication and consultation with customers through multiple channels and initiatives.

ENGLP uses a variety of channels, touchpoints, tools and tactics, as appropriate, to connect with customers and stakeholders, including bill inserts, print advertisements, news media, website updates, surveys and charitable community investments.

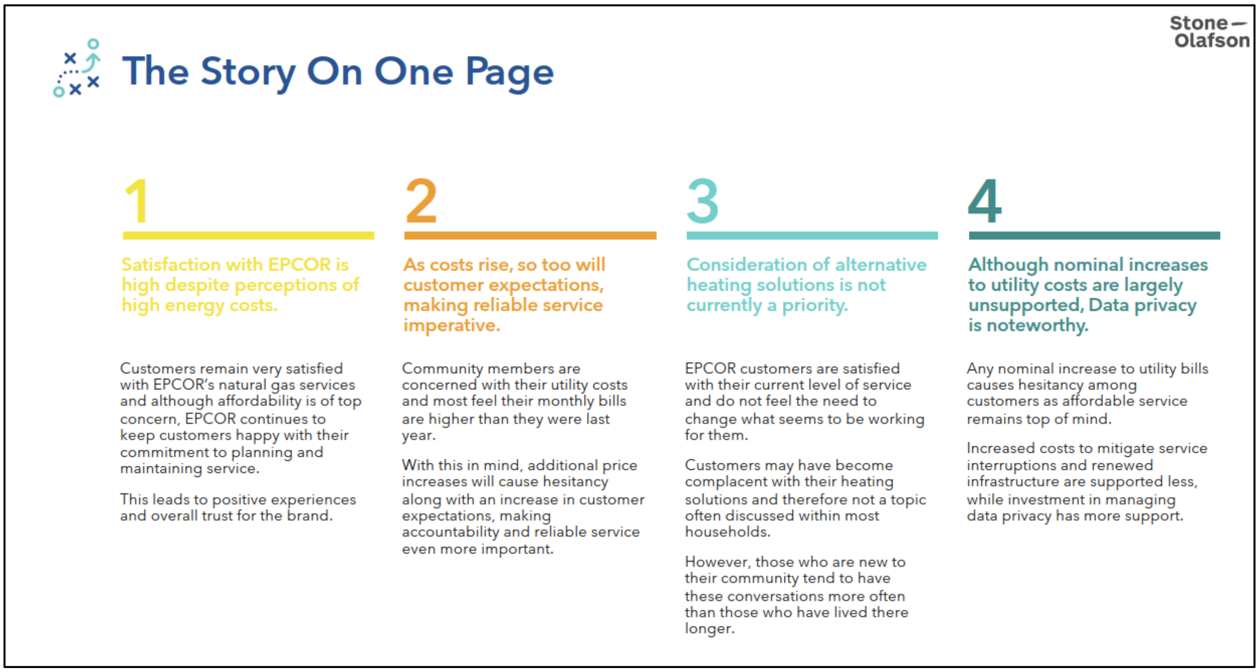
Table 1.6-1 in this Exhibit provides further detail on the various customer engagement activities and touchpoints provided by ENGLP Staff.

1.6.1. Utility System Plan Customer Engagement

ENGLP engages with customers in a variety of ways regarding safety, system reliability, billing and its community presence. The utility works hard to communicate and engage with customers in its distribution area and to ensure that customer service and capital investment is prudent, appropriate and aligns with community interests and priorities.

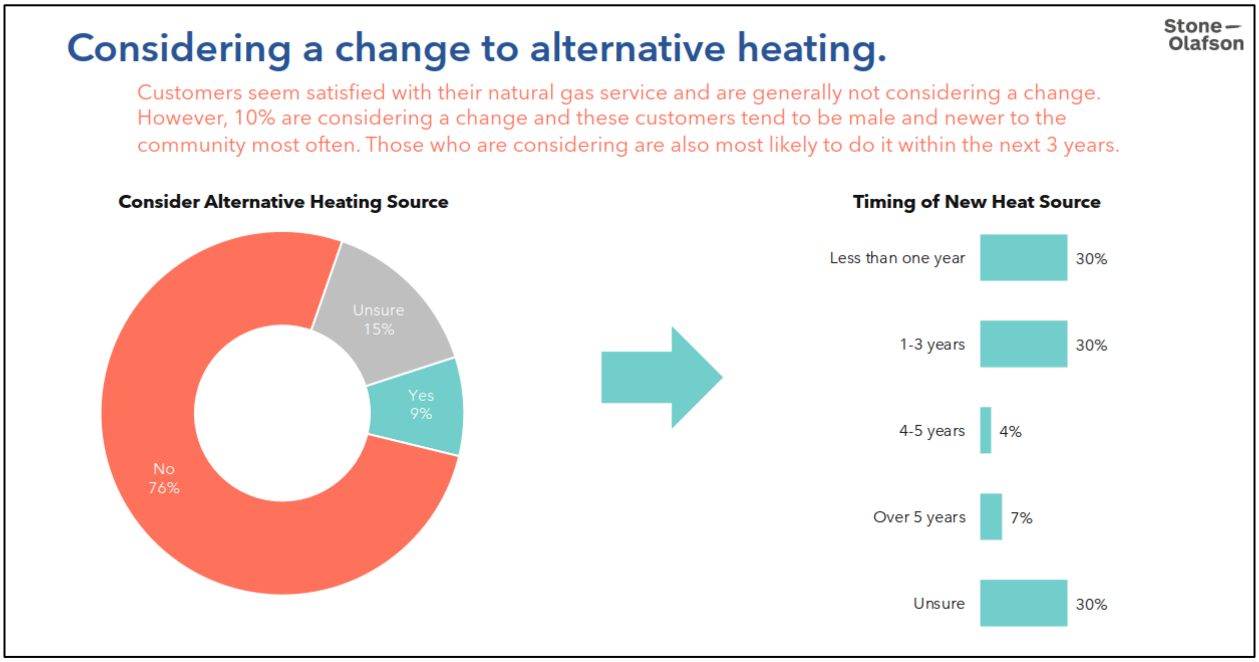
ENGLP uses a variety of channels and tools to connect with customers, including bill inserts, website updates, surveys and charitable community investments. In developing the forthcoming USP, ENGLP undertook a survey to gather feedback from customers in all rate classes which was a critical input to developing a prudent five year capital investment and maintenance plan. ENGLP retained Stone Olafson, a third party research company, to administer the survey in Q2 2024. The survey was conducted to identify satisfaction of customers in the distribution area, their willingness to invest more for increased operational demand, and their appetite for alternative energy sources in the future. A total of 307 responses were received, providing a margin of error of ±5.5%, 19 times out of 20.

There were some key findings as a result of the customer survey. Our customers have told us that they remain very satisfied with ENGLP's natural gas service. Affordability and reliability remain top concerns. Satisfaction with ENGLP remains high, despite perceptions of high energy costs. As costs rise, so too do customers' expectations. With this in mind, additional price increases will increase customer expectations, making accountability and reliability of service even more important. Lastly, cost increases to mitigate service interruptions and renewed infrastructure are supported less, while investment in managing data privacy has more support. A copy of the survey results have been provided in the USP in Exhibit 2.



ENGLP's customers expect consistent and affordable service, without interruption. In the past few years, customers have experienced a large fluctuation in their bills due to significant increases in commodity pricing plus the continued escalation of the Federal Carbon Charge on their bills, beyond the rate of inflation. While ENGLP does not control these costs, it understands that all rates on the bills do impact customers and has considered this when building out its USP and investment strategies. The table below highlights the increases in costs:

Annual Bills	**2020** **EB-2018-0336**	**2021** **EB-2020-0234**	**2022** **EB-2021-0215**	**2023** **EB-2022-0183**	**2024** **EB-2023-0160**	**Annual Change %**
Commodity	$310	$280	$248	$507	$481	11%
Delivery/Rate Riders	$463	$527	$522	$520	$574	5%
Federal Carbon Charge	$0	$124	$147	$187	$256	27%
Total	$772	$931	$917	$1,214	$1,312	14%



ENGLP continues to experience increased demand for natural gas service from both residential and commercial customers. While energy transition is a significant topic of discussion in the industry, it doesn't appear to be on the forefront for ENGLP's customers. ENGLP has experienced an increase in customer count by approximately 140 per year (1.8% annual average) over the five year rate term. ENGLP's USP is largely structured to accommodate this growth but also replacement of short-term life asset infrastructure (i.e. meters) as required by government standards.

1 **Table 1.6-1 - Summary of Customer Engagement Activities**

Provide a list of customer engagement activities	Provide a list of customer needs and preferences identified through each engagement activity	Actions taken to respond to identified needs and preferences. If no action was taken, explain why.
Customer Education - Bill Inserts and Email Campaigns	Bill inserts and messaging provides an opportunity for customers to be made aware of changes in the industry that could impact them. This can include rate changes, pricing optionality, health and safety, conservation and low income support. The regulatory environment is complex and this medium provides an opportunity to proactively inform customers of changes that could impact them.	Every ENGLP customer is billed monthly. As such, this continues to be a good avenue to reach all customers. Periodic billing inserts provide current rate information and other important safety considerations. ENGLP prepares a communication plan annually to schedule important customer communications allowing for flexibility to address industry changes. ENGLP also ran an e-billing campaign in 2023 to inform customers of the option of receiving their bills electronically, reducing its impact on the environment.
Customer Education - Dig Safety Awareness Inserts	Education and Safety - There is a need for the community to understand the dangers of digging without the proper locates.	ENGLP coordinated a mail insert to help educate and inform the community.
Customer Support - Financial Assistance Programs (LEAP)	ENGLP provides support through the United Way with the province's Low-income Energy Assistance Program (LEAP). These emergency financial assistance programs are designed to help low-income customers who have difficulty making their natural gas bill payments.	ENGLP continues to promote financial assistance programs that are available to assist low-income customers through social media, the LDC's website, telephone calls and e-mails, as well as bill inserts
Customer Support - Commercial Customer Engagement	We have regular meetings with some of our larger clients to ensure they receive appropriate levels of service and to ensure we are meeting all of their needs.	This allows ENGLP to interact with some of our bigger clients, receive feedback and work collaboratively on how to improve its system.

Provide a list of customer engagement activities	**Provide a list of customer needs and preferences identified through each engagement activity**	**Actions taken to respond to identified needs and preferences. If no action was taken, explain why.**
Customer Support - Customer visits to the Office	Prior to the pandemic, customers could come directly into ENGLP's office to drop off any forms, or ask any questions they have regarding their natural gas service. Since the pandemic, customers can still book an appointment to come into the office and receive assistance, if needed.	This allowed us to have face-to-face conversations with those in the community that ENGLP services. ENGLP has not experienced many individuals schedule appointments since closing the office to the public.
Customer Support - Customer Service Phone Calls	ENGLP takes 6,000 calls a year from its customer base to answer any questions regarding billing, emergency gas leaks, meter replacements, etc. ENGLP also responds to customer e-mails in a timely manner to ensure customers receive prompt responses to their questions or concerns. ENGLP's hours are 8 am - 4pm Monday - Friday (excluding holidays).	This allows ENGLP to receive real-time feedback from its customers regarding their services, and allows the customer to call or e-mail ENGLP to receive information regarding their natural gas service.
Annual Meeting & Presentation With Municipalities	With support from Public Affairs - deliver presentations to Municipalities of Aylmer, Bayham, Malahide, Elgin County, and SouthWest Oxford Township.	Engaging with Mayors and Council members to explore opportunities to work with them as good corporate citizens.
Quarterly Meetings with Lagasco	Quarterly meeting to discuss operational and gas supply related issues.	Explore opportunities to work together to keep the communities safe.
Annual Meetings with Developer and Builders	Meetings with local developers and builder to discuss working around ENGLP gas pipeline assets diligently to prevent line strikes.	Working together to reduce and prevent line strikes based on their use of heavy equipment around our buried pipe.
IGPC Engagement during Major Project on 6" Line	Engage IGPC on all aspect of planned work on the IGPC 6" steel that may have potential disruption to their operations.	Ensure IGPC employees are informed regarding what steps and activities that EPCOR is completed to ensure the integrity and reliability of the gas supply to their facility with minimal disruption.

Provide a list of customer engagement activities	Provide a list of customer needs and preferences identified through each engagement activity	Actions taken to respond to identified needs and preferences. If no action was taken, explain why.
Community Engagement - EPCOR Heart + Soul Fund	Through EPCOR's Heart + Soul Fund, just under $30,000 was invested into 10 organizations that focus on delivering arts, culture, charitable and mental health supports.	In 2020, EPCOR launched the Heart + Soul Fund to help arts, culture and non-profit sectors impacted by the COVID-19 pandemic. From 2020 - 2022, EPCOR supported local programming that helped organizations build resiliency, uplift our communities and enabled them to continuing to do what they do best: bringing the heart and soul to the communities we serve.
Community Engagement - United Way Day of Caring	ENGLP provided support through the United Way to the Re-store in Aylmer and learned of the needs of the community through conversations with workers and volunteers at the re-store.	In 2023, EPCOR assisted with pulling weeds and breaking down boxes at the Re-store in Aylmer, which is a locally owned and operated thrift store, and also recorded some radio ads for the local radio station that broadcasts in Low German.
Aylmer Spitfires Jr. C Hockey Club	Community Giving - we provided $1,500 to the local hockey team as an equipment sponsor.	This gives ENGLP a chance to give back to the communities it serves.
East Elgin School Scholarship	Community Giving - we provided $1,000 to a student as a scholarship	This gives ENGLP a chance to give back to the community in which we serve.
United Way BBQ	Face-to-face community events provides an opportunity for ENGLP to interact with commercial businesses in our service area. ENGLP invites local businesses to come out and have food, and support a cause that directly gives back to the communities it serves.	ENGLP holds the annual BBQ, which helps raise community awareness and provides an opportunity to interact with the community in a unique way.

1.7. Performance Management and Scorecard

ENGLP currently meets the scorecard which was approved in the previous cost of service filing. The scorecard was established based on the filing guidelines (page 15):

> *"The Rate Handbook established that the OEB's scorecard approach to performance measurement will be applied to natural gas utilities. Each utility is required, in its first rate application following the issuance of the Rate Handbook, to propose a scorecard that will be used to measure and monitor its performance and, where appropriate, enable comparisons between or among gas utilities.*
>
> *The format of the proposed scorecard should be similar to the scorecard developed for electricity distributors (available on the OEB's website) and must include measures for customer focus, operational effectiveness, public policy responsiveness, and financial performance. In the scorecard proposal, the applicant is expected to discuss its plans for continuous improvement. The applicant may propose additional performance categories or measures that it believes would be meaningful for its operations as a natural gas utility. Scorecard reporting is expected during the term of the incentive plan, as the data becomes available[2].*

ENGLP has included a copy of its scorecard from 2020-2023 and notes that there may be some variances between the table below, and between the values published in the OEB yearbook due to the combined submission of Aylmer and Southern Bruce in the annual regulatory reporting requirements (RRR). ENGLP notes that the utility has consistently performed well above the Board's targets where provided. The data below is only for the Aylmer operations:

Table 1.7-1 ENGLP Aylmer – 2020-2023 Scorecard

Performance Categories	Measures	Description	2020	2021	2022	2023
Service Quality	Reconnection response time (# of days to reconnect a customer)	*# of reconnections completed within 2 business days/# of reconnections completed*	100%	100%	96%	100%
	Scheduled appointments met on time (appointments met within designated time period)	*# of appointments met within 4hrs of the scheduled date / # of appointments scheduled in the month*	100%	100%	100%	98%
	Telephone calls answered on time (call answering service level)	*# of calls answered within 30 seconds / # of calls received*	96%	89%	89%	92%
Customer Satisfaction	Customer Complaint Written Response (# of days to provide a written response)	*# of complaints requiring response within 10 days / # of complaints requiring a written response*	100%	100%	100%	100%
	Billing accuracy	*Number of manual checks done as per quality assurance program, for excessively high or low usage.*	189	159	197	227
	Abandon Rate (# of calls abandon rate)	*# of calls abandoned while waiting for a live agent / # of calls requesting to speak to a live agent*	4%	4%	3%	2%
	Time to reschedule missed appointments	*% of rescheduled work within 2 hours of the end of the original appointment time*	100%	100%	100%	100%
Safety, system reliability and asset management	Meter Reading Performance	*# of meters with no read for 4 consecutive months / # of active meters to be read*	0.00%	0.00%	0.01%	0.00%
	% of Emergency Calls Responded within One Hour	*# of emergency calls responded within 60 minutes / # of emergency calls*	97.5%	97.6%	98.5%	97.9%
	Damages	*Third party line breaks per 1,000 locate requests*	4.6	4.3	7	4.2
Extending natural gas distribution to new communities	New communities that have access to natural gas distribution system	*(# of communities serviced by system)*	6	7	7	7
	$/m3 cost to deliver natural gas	*Actual average $/m3*	$0.058	$0.058	$0.062	$0.060
	Customer years	*Average customer years*	N/A	N/A	N/A	N/A
	Cumulative volume	*Actual cumulative volume*	N/A	N/A	N/A	N/A
Financial Ratios	Current Ratio		0.50	1.20	0.83	0.71
	Debt Ratio		0.47	0.26	0.31	0.30
	Debt to Equity Ratio		1.58	1.58	1.68	1.65
	Interest Coverage		2.03	2.26	2.29	2.54
	Financial Statement Return on Assets		2%	2%	3%	3%
	Financial Statement Return on Equity		5.2%	6.9%	7.8%	9.4%
	Total Cost per Customer per year		$531	$536	$587	$580
	Total Cost per km of distribution pipe per year		$4,408	$4,540	$5,062	$5,105

1.8. Financial Information

ENGLP has included the audited 2020-2023 financial statements in this Exhibit (Exhibit 1, Tab 2, Schedule 1). These financial statements include both Aylmer and Southern Bruce financial data as both areas of operations comprise a singular limited partnership.

A detailed reconciliation from the financial results to the regulatory results has been included as Exhibit 1, Tab 2, Schedule 2.

ENGLP has also included Pro-forma Financial Statements for the Bridge and Test Year as Exhibit 1, Tab 2, Schedule 3.

Additional information regarding its ultimate parent company, EUI, can be found on SEDAR. SEDAR is the official site that provides access to most public securities documents and information filed by issuers with the thirteen provincial and territorial securities regulatory authorities ("**Canadian Securities Administrators**" or "**CSA**") in the SEDAR filing system.

https://sedar.com/DisplayProfile.do?lang=EN&issuerType=03&issuerNo=00012250

ENGLP does not have any specific rating agency reports or prospectuses, etc. for recent and planned public issuances.

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

There have not been changes to the corporation’s tax status since the last rebasing, nor are there any planned changes.

ENGLP has incorporated the main categories of accounts as stated in the Uniform System of Accounts for Class A Gas Utilities in the preparation of this Application.

ENGLP adopted International Financial Reporting Standards ("**IFRS**") for use effective January 1, 2017.

ENGLP confirms that accounting treatment of any non-utility business has segregated activities from rate regulated activities.

1.9. Distributor Consolidation

In accordance with the filing requirements:

> *In the first cost of service application following a consolidation, the applicant is expected to address any rate-making aspects of the MAADs transaction, including a rate harmonization plan and /or customer rate classifications post consolidation.*

As this is the second cost of service application following EPCOR's acquisition, this section is not applicable.

ENGLP - List of Accounting Orders

EPCOR NATURAL GAS LIMITED PARTNERSHIP - Aylmer

Accounting Order

Unaccounted for Gas Variance Account

The Unaccounted For Gas Variance Account (“UFGVA”) is to record the cost of gas for EPCOR Natural Gas Limited Partnership’s Aylmer operations for Rates 1-5 that is associated with volumetric variances between the actual volume of Unaccounted for Gas (“UFG”) and the Board approved UFG forecast included in the determination of rates.

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

The 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.

The audited balances in this account, together with any carrying charges, will be brought forward for approval for disposition from/to Rates 1-5 on an annual basis.

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

Accounting Entries[3]

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

Debit/Credit Account No. 179.13 Unaccounted For Gas Variance Account (UFGVA)

Credit/Debit Account No. 623 Cost of Gas

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

Debit Account No. 140 Sundry Accounts Receivable

Credit Account No. 179.13 Unaccounted For Gas Variance Account (UFGVA)

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

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

Credit/Debit Account No. 323 Other Interest Expense

[3] 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

Accounting Entries for Regulatory Expense Deferral Account (“REDA”)[4]

To record monthly as a debit (credit) in Deferral Account No. 179-21 (REDA) the cost for participating in generic proceedings and Union Gas proceedings, including a main rates case.

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-2006-0 117.

[4] 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

Purchased Gas Transportation Variance Account from Rates 1-5

As the transportation costs are a flow-through to customers, EPCOR Natural Gas Limited Partnership ("ENGLP") has an established Purchased Gas Transportation Variance Account Rates 1-5 ("PGTVA 1-5") to record differences between forecasted transportation costs included in ENGLP's approved rates via the Transportation Charge, and the actual transportation costs incurred by ENGLP. The PGTVA also records amounts related to deferral account dispositions received or invoiced from ENGLP's transportation suppliers.

Simple interest will be computed monthly on the opening balance in PGTVA 1-5 in accordance with the methodology approved by the Board in EB-2006-0017.

Accounting Entries[5]

To record the monthly difference between the Transportation Charge, and the actual transportation costs incurred by ENGLP under its M9 and Bundled T contracts with Enbridge Gas Inc. for the volumes required to serve the customers in rate classes 1-5:

Debit/Credit Account No. 179-45 Purchased Gas Transportation Variance Account Rates 1 -5 (PGTVA 1-5)

Credit/Debit Account No. 623 Cost of Gas

To record simple interest on the opening monthly balance in the PGTVA 1-5:

Debit/Credit Account No- 179-46 Interest on PGTVA 1-5

Credit/Debit Account No. 323 Other Interest Expense

[5] 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

Approved Deferral/Variance Disposal Variance Account

The Approved Deferral/Variance Disposal Variance Account ("ADVADA") is to record all deferral and variance account balances which have been approved for disposition/recovery. EPCOR Natural Gas Limited Partnership ("ENGLP") will account for this balance in the same manner as Account 1595 (Disposition and Recovery/Refund of Regulatory Balances Control Account) as per the Uniform Chart of Accounts for Electricity Distributors by recording a debit/credit in an appropriate sub-account (principal balances, carrying charges or carrying charges for net principal). Deferral and variance account balances which have been approved for disposition by the Board, will be transferred into the ADVADA and appropriate sub-account (categorized based on the year of disposition). Amounts recovered from or refunded to ratepayers through the associated approved rate rider(s) will be recorded against the balance in the ADVADA.

Once the approved period for recovery/refund has ended, balances resulting from over or under collection/refund, together with any carrying charges, will be brought forward for disposition at a future proceeding.

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

Accounting Entries[6]

To transfer the balance of deferral and variance accounts upon receipt of approval for disposition:

Debit/Credit Account No. 179.90 Approved Deferral/Variance Disposal Variance Account ("ADVADA")

Credit/Debit Account No. 179.XX Deferral/variance account

To transfer the balance of deferral and variance interest accounts upon receipt of approval for disposition:

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

Debit/Credit Account No. 179.91 Approved Deferral/Variance Disposal Variance Account Interest Sub-Account

Credit/Debit Account No. 179.XX Deferral/variance account interest

To record amounts recovered from /refunded to ratepayers through the approved rate rider(s) over the period for which the rate rider(s) are in effect:

Debit/Credit Account Account No. 300 Operating Revenue

Credit/Debit Account No. 179.90 Approved Deferral/Variance Disposal Variance Account ("ADVADA")

Credit/Debit Account No. 179.91 Approved Deferral/Variance Disposal Variance Account Interest Sub-Account

To record simple interest on the opening monthly balance of the ADVADA:

Debit/Credit Account No. 179.92 Interest on Net Principal of Approved Deferral/Variance Disposal Variance Account

Credit/Debit Account No. 323 Other Interest Expense

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 cumulative 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 cumulative ROE will be calculated as the sum of actual regulated net income over the term, 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 cumulative 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 for approval for disposition after the end of the Price Cap IR Term, once cumulative earnings over the 2025-2029 term have been assessed and the actual ESM amount has been determined.

As any balance in this account is not owing until earnings over the entire 2025-2029 term are assessed as over-earned under the ESM, interest will not be computed on the balance in the ESMDA.

Accounting Entries[7]

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

---

[7] 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[8]

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.

[8] 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

Accelerated CCA Income Taxes Variance Account

The Accelerated CCA Income Taxes Variance Account ("ACITVA") is 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 2020 revenue requirement (EB-2018-0336) and the accelerated CCA rates as enacted under Bill C-97, should EPCOR Natural Gas Limited Partnership ("ENGLP") claim accelerated CCA for its Aylmer operations during the Price Cap IR Term. In the calculation of income taxes payable included in the 2020 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.

In the event that ENGLP claims accelerated CCA, the annual amount recorded in the ACITVA will be the tax impact at the approved income tax rate in EB-2018-0036, on the difference between accelerated CCA calculated on the rate base approved in the same proceeding and CCA included in income taxes payable approved in the same proceeding.

The entire audited balance in this account, together with any carrying charges, will be brought forward for approval for disposition on an annual basis.

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

Accounting Entries[9]

To record the income tax impact on the difference between accelerated CCA (if claimed by ENGLP) and CCA included in income taxes payable of the approved revenue requirement:

Debit/Credit Account No. 179.72 ACTIVA

Credit/Debit Account No. 306 Income Tax Expense

To record simple interest on the opening monthly balance of the ACITVA:

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

Debit/Credit Account No. 179.73 Interest on ACTIVA

Credit/Debit Account No. 323 Other Interest Expense

EPCOR NATURAL GAS LIMITED PARTNERSHIP - Aylmer

Accounting Order

Account 179 – LEAP EFA Funding Deferral Account

For the purpose of recording incremental Low-income Energy Assistance Emergency Financial Assistance (LEAP EFA) contributions that are beyond the amounts currently embedded in distribution rates, rate-regulated natural gas distributors may establish the following two new accounts effective March 1, 2024:

1. Account 179 - LEAP EFA Funding Deferral
2. Account 179 - LEAP EFA Funding Deferral, Carrying Charges

In the LEAP EFA Funding Deferral sub-account, distributors may record prudently incurred incremental LEAP EFA contributions made on and after March 1, 2024 that are beyond the amounts currently embedded in distribution rates.

Carrying charges will apply at the OEB's prescribed rates for deferral and variance accounts that are published on the OEB's website on a quarterly basis.2

A distributor may bring forward amounts recorded in the LEAP EFA Funding Deferral sub-accounts for review and disposition as part of its next cost-based (rebasing) rate application if they exceed the distributor's materiality threshold. The OEB will also allow

distributors that are in an extended incentive rate-setting period (e.g. under a deferred rebasing period arising from utility consolidations) to request material account balances for disposition in a non-rate rebasing year to address potential intergenerational inequity concerns.

The incremental LEAP EFA funding contributions shall be tracked at a sufficiently detailed level to assist in a prudence review of the costs incurred.

The OEB also expects that any distributor that has a material balance in the LEAP EFA Funding Deferral sub-accounts will, as part of its next cost-based rate application, apply for a higher LEAP EFA funding amount going forward if the need for additional funding is forecast to be sustained. As such, the OEB does not anticipate that distributors will need the LEAP EFA Funding Deferral sub-accounts beyond their next cost-based rate application.

<u>**Sample Journal Entries:**</u>

To record incremental LEAP EFA contributions:

Dr. 179 LEAP EFA Funding Deferral

Cr. XXXX Account(s) associated with LEAP costs, as applicable

To record incremental LEAP EFA contributions, if applicable.

Dr. 179 LEAP EFA Funding, Carrying Charges

Cr. 323 Other Interest Expense

To record the carrying charges on the monthly opening balance in Account 179 LEAPEFA Funding Deferral

EPCOR NATURAL GAS LIMITED PARTNERSHIP - Aylmer

Accounting Order

Accounting Order (003-2023) for Cloud Computing Implementation Costs

Natural gas distributors may establish similar sub-accounts under Account 179 – Other Deferred Charges. This accounting order also applies to Ontario Power Generation Inc.

In the Incremental Cloud Computing Implementation Costs account, utilities may record incremental cloud computing implementation costs incurred and any related offsetting savings, if applicable. Carrying charges will apply at the OEB's prescribed rates for deferral and variance accounts that are published on the OEB's website on a quarterly basis, unless otherwise directed by the OEB.

Utilities are expected to track costs at a sufficiently detailed level or category to assist in a prudence review of the costs incurred.

The OEB will assess any claimed costs recorded in the account at the time the disposition of the account balances is requested, subject to the applicable criteria for causation, materiality, and prudence.

Sample Journal Entries

To record incremental cloud computing implementation costs:

Dr. 1511 Incremental Cloud Computing Implementation Costs

Cr. XXXX OM&A Account(s) associated with cloud costs, as applicable

To record incremental cloud computing implementation costs incurred and any related offsetting savings, if applicable

Dr. 1511 Incremental Cloud Computing Implementation Costs, Sub-account Carrying Charges

Cr. 6035 Other Interest Expense

To record the carrying charges on the net monthly opening balance in Account 1511 Incremental Cloud Computing Implementation Costs

EPCOR NATURAL GAS LIMITED PARTNERSHIP - Aylmer

Accounting Order

ACCOUNT 179 – OTHER DEFERRED CHARGES, GETTING ONTARIO CONNECTED ACT (GOCA) VARIANCE ACCOUNT

Gas utilities may establish a new Account 179 – Other Deferred Charges, Getting Ontario Connected Account Variance Account to record the variance between locate costs resulting from Bill 93 and the approved cost included in base rates.

This account includes costs incurred to enable the locate activities. Utilities are expected to track costs at a sufficiently detailed level to assist in a prudence review of the costs incurred, materiality, and causation related to Bill 93 at the time of disposition. Specifically, utilities are to demonstrate that recorded amounts in their accounts are both incremental to the base rates and are a direct result of Bill 93

The following accounts are established to record the amounts described above incurred on or after April 1, 2023:

- Account 179, GOCA Variance Account
- Account 179, GOCA Variance Account Carrying Charges

Gas utilities will record interest on the balance in the sub-account using the prescribed interest rates set by the OEB. Simple interest will be calculated on the opening monthly balance of the account until the balance is fully disposed.

The following outlines the proposed accounting entries for this variance account.

<u>Entry #1</u>

<u>USofA #Account Description</u>

DR 179GOCA Variance Account

CR 728General Expense

To record actual locate costs associated with Bill 93

<u>Entry #2</u>

<u>USofA #Account Description</u>

DR 179GOCA Variance Account

CR 728General Expense

To record actual ongoing locate costs that are not associated with Bill 93.

Please note that the costs recorded in Entry #1 and Entry #2 would be equal to 100% actual locate costs incurred by the utility for the period.

Entry #3

USofA #Account Description

DR 319 Other Income

CR 179GOCA Variance Account

To record the locate "revenue" amount representing the OM&A expense related to the locate services that were approved in base rates, escalated accordingly by the annual rate adjustments in the distributor's IRM decision(s) and order(s) or the locate "revenue"

amount representing the approved OM&A amount related to the locates in the distributor's custom IR decision and order.

Entry #4

UsofA #Account Description

DR 179GOCA Variance Account, Carrying Charges
CR 323Other Interest Expense

To record carrying charges on the opening principal balance of the GOCA Variance Account, using the OEB's prescribed interest rates.

EPCOR NATURAL GAS LIMITED PARTNERSHIP - Aylmer

Accounting Orders to be Closed

EPCOR NATURAL GAS LIMITED PARTNERSHIP - Aylmer

Accounting Order

Loss on Disposal of Meters Deferral Account

The Loss on Disposal of Meters Deferral Account ("LDMDA") is to record the loss on disposal of residential (AC-250) meters resulting from the change in the useful life in 2020 for its Aylmer operations. A change in depreciation rate is necessitated by the fact that a new residential meter has a seal life of ten years and the full replacement of the meter at the end of the seal life is more economical than refurbishment. The change in the depreciation rate for these meters from 3.62% to 10% in 2020 will result in a loss on disposal equal to the net book value of the meters that have been in service for ten years or more.

The balance in this account, together with any carrying charges, will be brought forward for approval for disposition at a future date once the balance has been audited. As these meters are currently used only for customers in Rate Class 1, when the account is brought forward for disposal a fixed-rate rate rider will be only be applied to Rate Class 1.

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

Accounting Entries[10]

To record the amount of the loss from the disposal of residential meters:

Debit Account No. 105 Accumulated Depreciation

Debit Account No. 179-70 Loss on Disposal of Meters Deferral Account (LDMDA)

Credit Account No. 100 Property Plant and Equipment

To record simple interest on the opening monthly balance of the LDMDA:

Debit Account No. 179-71 Interest on Disposal of Meters Deferral Account

Credit Account No. 323 Other Interest Expense

[10] 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

2016-2017 System Integrity Capital Deferral Account

The 2016-2017 System Integrity Capital Deferral Account ("SICDA") is to record monthly, in accordance with the Settlement Proposal for EB-2018-0336, as of January 1, 2020 one twelfth of the revenue requirement associated with the 2020 net book value of the four capital projects incurred by Natural Resource Gas Limited in 2016 and 2017 to address specified system integrity issues. The specific capital projects ("the Capital Projects") and their 2020 net book value are as follows:

1. $402,639 for the Enbridge Gas (formerly Union Gas) Bradley Station Project.
2. $748,383 for the pipeline from the Bradley Station to the Wilson Line project.
3. $498,922 for the pipeline from the existing Putnam Station to Colloden Line project.
4. $265,015 for the extension of the Springwater Road pipeline from south of Orwell to John Wise Line project.

The Parties to the Settlement Proposal in proceeding EB-2018-0336 agreed that pending the provision of further information to support these expenditures the above noted amounts for the Capital Projects were to be included in the 2020 Test Year rate base for the purposes of determining the revenue requirement and setting rates for 2020 through 2024 in EPCOR Natural Gas Limited Partnership's ("ENGLP") rate application EB-2018-0336. Accordingly, one-twelfth of the associated 2020 Test Year revenue requirement shall be recorded monthly in the SICDA pending the review of evidence in support of establishing prudency of the Capital Projects by the Board in a future proceeding.

The balance in the SCIDA will be addressed through a separate proceeding wherein the Board will determine the prudency of the Capital Projects, establish a methodology for the disposition or discontinuation of the deferral account and if deemed imprudent determine the appropriate mechanism for ENGLP to refund to ratepayers the revenue requirement for the Capital Projects for the remaining term of the 2020-2024 application.

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

<u>Accounting Entries</u>[11]

---

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

To record effective January 1, 2020 the monthly revenue requirement associated with the 2020 net book value of the Capital Projects incurred by Natural Resource Gas Limited in 2016 and 2017 to address system integrity issues:

Debit Account No. 300 Operating Revenue

Credit Account No. 179.78 2016-2017 System Integrity Capital Projects Deferral Account ("SICDA")

To record simple interest on the opening monthly balance of the SICDA:

Debit Account No. 323 Other Interest Expense

Credit Account No. 179.79 Interest on 2016-2017 System Integrity Capital Deferral Account

ENGLP – Audited Financial Statements

Financial Statements of

EPCOR NATURAL GAS LIMITED PARTNERSHIP

Years ended December 31, 2021 and 2020

Tel: 519-432-5534
Fax: 519-432-6544
www.bdo.ca

BDO Canada LLP
633 Colborne St., Suite 230
London ON N6B 2V3

INDEPENDENT AUDITOR'S REPORT

To the Board of Directors of
EPCOR Ontario Utilities Inc.

Opinion

We have audited the financial statements of EPCOR Natural Gas Limited Partnership (the Entity), which comprise the statement of financial position as at December 31, 2021, and the statement of comprehensive income (loss), statement of changes in equity and statement of cash flows for the years ended, and notes to the financial statements, including a summary of significant accounting policies.

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Entity as at December 31, 2021, and its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards.

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the Auditor's Responsibilities for the Audit of the Financial Statements section of our report. We are independent of the Entity in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada, and we have fulfilled our other ethical responsibilities in accordance with these requirements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Entity's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Entity or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Entity's financial reporting process.

Auditor's Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness

of the Entity’s internal control.

- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management’s use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Entity’s ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor’s report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor’s report. However, future events or conditions may cause the Entity to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

BDO Canada LLP

Chartered Professional Accountants, Licensed Public Accountants

London, Ontario
April 14, 2022

EPCOR NATURAL GAS LIMITED PARTNERSHIP

Statements of Comprehensive Income (Loss)
(In thousands of Canadian dollars)

Years ended December 31, 2021 and 2020

	2021	2020
Revenue (note 6)	$ 16,431	$ 12,388
Operating expenses:		
Energy purchases	5,968	4,830
Staff costs and employee benefits expenses	1,780	1,644
Depreciation and amortization (note 7)	3,488	1,764
Other raw materials and operating charges	2,884	2,351
Franchise fees and property taxes	872	708
Other administrative expenses	3,034	2,959
	18,026	14,256
Operating (loss) income	(1,595)	(1,868)
Finance expenses (note 8)	(1,269)	(419)
Comprehensive (loss) income for the year - all attributable to the Partners	**$** (2,864)	$ (2,287)

The accompanying notes are an integral part of these financial statements

EPCOR NATURAL GAS LIMITED PARTNERSHIP

Statements of Financial Position
(In thousands of Canadian dollars)

December 31, 2021 and 2020

	2021	2020
ASSETS		
Current assets:		
Cash	$ 5	$ 6
Trade and other receivables (note 9)	3,917	8,261
Prepaid expenses	29	2
Inventories	515	385
	4,466	8,654
Non-current assets:		
Property, plant and equipment (note 10)	117,917	96,429
Intangible assets (note 11)	1,137	1,162
Goodwill (note 11)	1,808	1,808
	120,862	99,399
TOTAL ASSETS	$ 125,328	$ 108,053

	2021	2020
LIABILITIES AND EQUITY		
Current liabilities:		
Trade and other payables (note 12)	$ 8,991	$ 18,208
Loans and borrowings (note 13)	209	-
Customer deposits	378	249
Deferred revenue (note 14)	538	384
Provisions (note 15)	165	96
Current portion of lease liabilities (note 16)	40	30
	10,321	18,967
Non-current liabilities:		
Loans and borrowings (note 13)	52,160	37,660
Deferred revenue (note 14)	22,787	23,533
Lease liabilities (note 16)	31	-
	74,978	61,193
Total liabilities	85,299	80,160
Equity attributable to the Partners:		
Partnership units (note 17)	45,360	30,360
Deficit	(5,331)	(2,467)
Total equity – attributable to the Partners	40,029	27,893
TOTAL LIABILITIES AND EQUITY	$ 125,328	$ 108,053

Approved on behalf of the EPCOR Ontario Utilities Inc. Board of Directors,

Stuart Lee
Director, EPCOR Ontario Utilities Inc.

John Elford
Director, EPCOR Ontario Utilities Inc.

The accompanying notes are an integral part of these financial statements

EPCOR NATURAL GAS LIMITED PARTNERSHIP

Statements of Changes in Equity
(In thousands of Canadian dollars)

December 31, 2021 and 2020

	Partnership Units (note 17)	Deficit	Equity attributable to the Partners
Equity at December 31, 2019	$ 25,360	$ (180)	$ 25,180
Equity contribution from the Partners (note 17)	5,000	-	5,000
Comprehensive income for the year	-	(2,287)	(2,287)
Equity at December 31, 2020	$ 30,360	$ (2,467)	$ 27,893
Equity contribution from the Partners (note 17)	15,000	-	15,000
Comprehensive loss for the year	-	(2,864)	(2,864)
Equity at December 31, 2021	$ 45,360	$ (5,331)	$ 40,029

The accompanying notes are an integral part of these financial statements

EPCOR NATURAL GAS LIMITED PARTNERSHIP

Statements of Cash Flows
(In thousands of Canadian dollars)

Years ended December 31, 2021 and 2020

	2021	2020
Cash flows from (used in) operating activities:		
Comprehensive (loss) income for the year	$ (2,864)	$ (2,287)
Reconciliation of comprehensive (loss) income for the year to cash from (used in) operating activities:		
Interest paid (net)	(1,269)	(419)
Finance expenses (net)	1,269	419
Depreciation and amortization (note 7)	3,455	1,764
Loss (gain) on disposal of property, plant and equipment	33	-
Contribution adjustments (note 14)	255	18,357
Deferred revenue recognized (note 14)	(456)	(143)
Change in employee benefits provisions (note 15)	69	18
Net cash flows from operating activities before non-cash operating working capital changes	492	17,709
Changes in non-cash operating working capital (note 18)	(5,353)	6,264
Net cash flows from operating activities	(4,861)	23,973
Cash flows from (used in) investing activities:		
Acquisition or construction of property, plant and equipment[1] (note 10)	(25,279)	(38,123)
Acquisition of intangible assets (note 11)	(87)	(84)
Proceeds from sale of property, plant and equipment	105	-
Change in non-cash investing working capital (note 18)	452	1,060
Net cash flows used in investing activities	(24,809)	(37,147)
Cash flows from (used in) financing activities:		
Net (repayment) issuance of short-term loans and borrowings (note 19)	209	(21,725)
Proceeds from issuance of long-term loans and borrowings (note 19)	14,500	29,000
Payments of lease liabilities (note 19)	(40)	(39)
Equity contribution from the Partners (note 17)	15,000	5,000
Net cash flows from financing activities	29,669	12,236
Change in cash and cash equivalents	(1)	(938)
Cash and cash equivalents, beginning of year	6	944
Cash and cash equivalents, end of year	$ 5	$ 6

1 Interest payments of $237 (2020 - $531) have been capitalized and included in acquisitions and construction of property, plant and equipment (PP&E).

1. Description of business

(a) Nature of operations

EPCOR Natural Gas Limited Partnership (the Partnership) provides natural gas distribution service through its general partner EPCOR Ontario Utilities Inc. (the General Partner or EOUI) and operates within Southwestern Ontario under franchise agreements that are approved by the Ontario Energy Board (OEB).

The Partnership was formed on November 4, 2016 pursuant to a Certificate of Limited Partnership and a limited partnership agreement entered into between the General Partner and EPCOR Commercial Services Inc. (the Limited Partner) dated as of November 4, 2016 and operates in Ontario with its registered head office located at 77 King Street West, Suite 400, Toronto, Ontario M5K 0A1.

The Partnership is a limited partnership registered in Canada and is managed by the General Partner. Although the General Partner holds legal title to the assets, the Partnership is the beneficial owner and assumes all the risks and rewards of the assets.

The Partnership is indirectly 100% owned by EPCOR Utilities Inc. (EPCOR).

The Partnership operates two divisions that are geographically separated in Southwestern Ontario, referred to respectively as Aylmer (Aylmer Operations) and Southern Bruce (Southern Bruce Operations). The EPCOR Natural Gas Limited Partnership Financial Statements present the financial position, comprehensive income, change in equity and cash flows of both divisions.

(b) Rate regulation

The Partnership's Operations are regulated by the OEB pursuant to *The Ontario Energy Board Act* (Ontario), *The Energy Act* (Ontario) and regulations made under those statutes. The OEB administers these acts and regulations regarding tariffs, rates, construction, financing, operations, accounting and service area. Revenue rate schedules are approved periodically by the OEB and are designed to permit a fair and reasonable return to the Partnership on the utility investment. Realization of the allowed rate of return is subject to actual operating conditions experienced during the year.

Regulatory risk is the risk that the Province and its regulator, the OEB, could establish a regulatory regime that imposes conditions that restrict the natural gas distribution business from achieving an acceptable rate of return that permits financial sustainability of its operations, including the recovery of expenses incurred for the benefit of other market participants in the natural gas industry such as transition costs and other regulatory assets. All requests for change in natural gas distribution charges require the approval of the OEB.

Regulatory developments in Ontario's natural gas industry, including current and possible future consultations between the OEB and interested stakeholders, may affect distribution rates and other permitted recoveries in the future. The Aylmer Operations are subject to a cost of service regulatory mechanism under which the OEB establishes the revenues required (i) to recover the forecast operating costs, including depreciation and amortization and income taxes, of providing the regulated service, and (ii) to provide a fair and reasonable return on utility investment, or rate base. As actual operating conditions may vary from forecast, actual returns achieved can differ from approved returns. The current cost of service rates are applicable for years 2020through 2024. The Aylmer Operations' rates change annually based on a formula comprised of the following factors: inflation factor, productivity factor, and stretch factor. In addition and in limited circumstances, the Aylmer Operations has the ability to apply for supplementary funding for certain capital additions.

The Southern Bruce Operations are subject to a cumulative revenue regulatory mechanism under which the OEB establishes the revenues for a 10-year rate stability period. Southern Bruce Operations' rate stability period ends in December 2028. The Southern Bruce Operations' rates change annually based on a formula comprised of the following factors: inflation factor and stabilization factor.

The Partnership did not adopt IFRS 14 – *Regulatory Deferral Accounts* during the Partnership's initial adoption of IFRS.

2. Basis of presentation

(a) Statement of compliance

These financial statements have been prepared by management in accordance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board and Interpretations of the International Financial Reporting Interpretations Committee, and effective on December 31, 2021 and 2020. These financial statements were approved and authorized for issue by the Board of Directors of EOUI on April 16, 2021.

(b) Basis of measurement

The Partnership's financial statements are prepared on the historical cost basis.

(c) Functional and presentation currency

These financial statements are presented in Canadian dollars and all rounded to the nearest thousand dollars, except where otherwise stated.

3. Significant accounting policies

The accounting policies set out below have been applied consistently to all years presented in these financial statements unless otherwise indicated.

(a) Changes in significant accounting policies

The Partnership has adopted amendments to various accounting standards effective January 1, 2021, which did not have significant impact on these financial statements.

(b) Revenue recognition

The Partnership recognizes revenue when it transfers control over a promised good or service, a performance obligation under the contract, to a customer and where the Partnership is entitled to consideration resulting from completion of the performance obligation. Depending on the terms of the contract with the customer, revenue recognition can occur at a point in time or over time. When a performance obligation is satisfied, revenue is measured at the transaction price that is allocated to that performance obligation. For contracts where non-cash consideration is received, revenue is recognized and measured at the fair value of the non-cash consideration.

Customer contracts may include the transfer of multiple goods and services. Where the Partnership determines that the multiple goods and services are not distinct performance obligations, they are treated as single performance obligation.

Revenues are classified as natural gas sales and provision of services depending on the nature of each distinct performance obligation.

Contract costs for obtaining a customer contract are expensed as incurred unless they create an asset related to future contract activity that the Partnership expects to recover.

Significant judgement may be required to determine the number of distinct performance obligations within a contract and the allocation of transaction price to multiple performance obligations in a contract, and to determine whether the Partnership acts as a principal or agent for certain performance obligations. When multiple performance obligations are identified in a contract, the transaction price is allocated based on the stand-alone selling price of each performance obligation. If stand-alone selling price is not observable, the Partnership estimates the stand-alone selling price for each distinct performance obligation based on the related expected cost plus margin. The Partnership is acting as a principal when the Partnership controls the goods or services before transfer to the customer. The Partnership is acting as an agent when it is obliged to arrange for the provision of the goods and services by another party, that are not controlled by the Partnership before transfer to the customer. When the Partnership acts as an agent, the revenue is recognized net of any related costs incurred.

The Partnership's principal sources of revenue and methods applied to the recognition of these revenues in these financial statements are as follows:

3. Significant accounting policies (continued)

(b) Revenue recognition (continued)

Natural gas sales

The contracts with customers for the supply of natural gas consist primarily of perpetual contracts that are effective until terminated by the customer or the Partnership. The Partnership also has entered into fixed term contracts with some industrial customers to deliver gas over the specified term of the contract. The Partnership provides a series of distinct goods, which are simultaneously received and consumed by the customers. Each of the performance obligations is satisfied over time using the output method for recognition of revenue, i.e. the units of each good supplied to the customer.

Revenues are calculated based on the customer's usage of the goods during the period, at the applicable rates as per the terms of the respective contracts. Customers are generally billed on a monthly basis and payment is generally due within 30 days of billing the customer.

Provision of services

The contracts with customers for each of natural gas transmission and distribution services consist primarily of perpetual contracts that are effective until terminated by the customer or the Partnership. The Partnership has also entered into fixed term contracts with some industrial customers to deliver gas over the specified term of the contract. The Partnership provides a series of distinct services, which are simultaneously received and consumed by the customers. Each of the performance obligations is satisfied over time using the output method for recognition of revenue, i.e. quantifiable services rendered to the customer.

Revenues are calculated based on the services provided to the customer during the period, at the applicable rates as per the terms of the respective contracts. These revenues include an estimate of the value of services provided to the customers in the reporting period and billed subsequent to the reporting period. Customers are billed generally within a month and payment is generally due within 30 days of billing the customer.

(c) Income taxes

As a limited partnership, the Partnership is not taxed at the entity level under the Canadian Income Tax Act. All income tax consequences of its operations are borne by its Partners, on a pro rata basis, in proportion to their interest in the Partnership.

(d) Inventories

Small parts and other consumables, the majority of which are consumed by the Partnership in the provision of its goods and services to customers, and natural gas inventories are valued at the lower of cost and net realizable value. Cost includes the purchase price, transportation costs and other costs to bring the inventories to their present location and condition. The costs of inventory items that are interchangeable are determined on an average cost basis. For inventory items that are not interchangeable, cost is assigned using specific identification of their individual costs. Net realizable value is the estimated selling price in the ordinary course of business, less the estimated costs of completion and the estimated costs necessary to make the sale. Previous write-downs of inventories from cost to net realizable value can be fully or partially reversed if supported by economic circumstances. The Partnership estimates the value of inventory that is expected to be used in the construction of property, plant and equipment (PP&E) and reports this value as construction work in progress under PP&E.

(e) Leases

At the inception of a contract, the Partnership determines whether a contract is, or contains a lease. A contract is, or contains, a lease if the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration.

3. Significant accounting policies (continued)

(e) Leases (continued)

As a lessee

On initial identification of a lease contract, the Partnership recognizes a right-of-use (ROU) asset and a lease liability at the commencement of the lease contract. The lease liability is initially measured at the present value of the future unavoidable lease payments under the contract, discounted using the interest rate implicit in the lease contract. Where the implicit rate cannot be readily determined, the Partnership uses its incremental borrowing rate. Lease payments include fixed payments including in-substance fixed payments less any lease incentives receivable, variable lease payments that depend on an index or a rate, the exercise price of a purchase option or optional renewal period that the Partnership is reasonably certain to exercise and penalties for early termination of a lease contract unless the Partnership is reasonably certain not to terminate early. Subsequently, the lease liability is measured at amortized cost, using the effective interest method. The lease liability is re-measured to reflect any reassessments or lease modifications. Lease payments are allocated between the principal repayment of the lease liability and finance expense. The finance expense on the lease liability is charged to net income over the term of the lease contract to produce a constant periodic rate of interest on the remaining balance of the lease liability for each period.

The ROU asset is initially measured at cost which includes the initial lease liability, any lease payments made at or before commencement date less any lease incentives received, any initial direct costs and restoration costs. The ROU assets are depreciated on a straight-line basis over the shorter of the respective asset's useful life and the remaining term of the lease contract. The ROU assets are subsequently re-measured to reflect any reassessments or lease modifications. At each reporting date, ROU assets are reviewed for indications of impairment. In case it is determined that indications of impairment exist, the recoverable amount is estimated for ROU assets, which is the greater of value in use and fair value the Partnership expects to recover from sub-lease of the asset.

The Partnership presents lease liabilities within liabilities and ROU assets within PP&E in the statements of financial position.

The Partnership has elected not to recognize ROU assets and lease liabilities for lease contracts where the total term of the respective lease contract is less than or equal to 12 months or for low value lease contracts. The Partnership recognizes the payments relating to such leases (including principal and interest associated with these leases) as an expense on a straight-line basis over the lease term. These payments are presented within other administrative expense in net income.

(f) Property, plant and equipment

PP&E are recorded at cost, net of accumulated depreciation and accumulated impairment losses, if any.

Cost includes contracted services, materials, direct labor and directly attributable overhead costs on qualifying assets. Where parts of an item of PP&E have different estimated useful lives, they are accounted for as separate items (major components) of PP&E.

The cost of major inspections and maintenance is recognized in the carrying amount of the item if the asset recognition criteria are satisfied. The carrying amount of a replaced part is derecognized. The costs of day-to-day servicing are expensed as incurred. The cost of a group of PP&E acquired in a transaction, including those acquired in a business combination, is allocated to the individual assets acquired based on their fair value.

Depreciation of cost less residual value is charged on a straight-line basis over the estimated useful lives of items of each depreciable component of PP&E, from the date they are available for use, as this most closely reflects the expected usage of the assets. Land and construction work in progress are not depreciated. Estimating the appropriate useful lives of assets requires judgment and is generally based on estimates of life characteristics of similar assets. The estimated useful lives, methods of depreciation and residual values are reviewed annually with any changes adopted on a prospective basis.

3. Significant accounting policies (continued)

(f) Property, plant and equipment (continued)

The ranges of estimated useful lives for PP&E assets used are as follows:

Building and hardware	2 – 52 years
Machinery and equipment	6 – 15 years
Natural Gas distribution	6 – 51 years
Right-of-use assets	2 years

Gains or losses on the disposal of PP&E are determined as the difference between the net disposal proceeds and the carrying amount at the date of disposal.

(g) Capitalized borrowing costs

The Partnership capitalizes interest during construction of a qualifying asset using the weighted average cost of debt incurred on EPCOR's external borrowings or specific borrowings used to finance qualifying assets. Qualifying assets are considered those that take a substantial period of time to construct.

(h) Intangible assets

Intangible assets with finite lives are stated at cost, net of accumulated amortization and impairment losses, if any. The cost of a group of intangible assets acquired in a transaction, including those acquired in a business combination that meet the specified criteria for recognition apart from goodwill, is allocated to the individual assets acquired based on their relative fair value.

The cost of intangible software includes the cost of license acquisitions, contracted services, materials, direct labor, and directly attributable overhead costs on qualifying assets.

Other rights represent the costs to acquire Franchise rights. Other rights are recorded at cost at the date of acquisition. Subsequent expenditures are capitalized only when it increases the future economic benefit in the specific asset to which it relates.

Amortization of the cost of finite life intangible assets is recognized on a straight-line basis over the estimated economic useful lives of the assets, from the date they are available for use, as this most closely reflects the expected usage of the asset. Work in progress is not amortized. The estimated economic useful lives and methods of amortization are reviewed annually with any changes adopted on a prospective basis.

The estimated economic useful lives for intangible assets with finite lives are as follows:

Software	10 years
Other rights	20 years

Gains or losses on the disposal of intangible assets are determined as the difference between the net disposal proceeds and the carrying amount at the date of disposal.

(i) Deferred revenue

Certain assets may be contributed by customers or constructed using non-refundable cash contributions from customers. Non-refundable customer contributions received towards construction or acquisition of an item of PP&E, which are used to provide ongoing goods or services to these customers, are recorded as deferred revenue. Deferred revenue is initially recorded at the fair value of contributed assets, or the amount of cash contributions received, and is recognized as revenue on a straight-line basis over the shorter of estimated lives of the respective contracts with the customers or the useful life of the related asset. Where contracts with customers are perpetual and the related contributed asset is used to provide ongoing goods or services to customers, the life of the contract is estimated to be equivalent to the useful life of the asset to which the contribution relates.

Certain assets are acquired or constructed using non-refundable government grants. Government grants are recorded as deferred revenue and are recognized as revenue on a straight-line basis over the estimated useful lives of the assets to which they relate.

3. Significant accounting policies (continued)

(j) Provisions

A provision is recognized if, as a result of a past event, the Partnership has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability. The increase in the provision due to the passage of time is recognized as a finance expense over the estimated period until settlement of the obligation.

(k) Non-derivative financial instruments

Financial assets and financial liabilities are identified and classified as measured at amortized cost.

Financial assets and financial liabilities are presented on a net basis when the Partnership has a legally enforceable right to offset the recognized amounts and intends to settle on a net basis or to realize the asset and settle the liability simultaneously.

Recognition and Measurement

Cash and trade and other receivables are classified as financial assets measured at amortized cost.

These financial assets are recognized initially at fair value plus directly attributable transaction costs, if any. After initial recognition, they are measured at amortized cost using the effective interest method less any impairment as described in note 3(l). The effective interest method calculates the amortized cost of a financial asset and allocates the finance income over the term of the financial asset using an effective interest rate. The effective interest rate is the rate that discounts estimated future cash receipts through the expected life of the financial asset, or a shorter period when appropriate, to the gross carrying amount of the financial asset.

The Partnership's trade and other payables, customer deposits and loans and borrowings are classified as financial liabilities measured at amortized cost and are recognized on the date at which the Partnership becomes a party to the contractual arrangement. Financial liabilities are initially recognized at fair value, plus directly attributable transaction costs, if any. Subsequently, these liabilities are measured at amortized cost using the effective interest rate method.

Derecognition

Financial liabilities are derecognized when the contractual obligations are discharged, cancelled or expire.

(l) Impairment of financial assets

The Partnership uses the "expected credit loss" (ECL) model for calculating impairment and recognizes ECL as a loss allowance for financial assets measured at amortized cost.

For trade receivables without a significant financing component, the Partnership applies the simplified approach and uses a provision matrix that is based on the Partnership's historical credit loss experience, current market conditions and forward-looking information, to estimate and recognize the lifetime ECL. Trade and other receivables that are not assessed for impairment individually are assessed for impairment on a collective basis taking into consideration the unique risk factors associated with each customer group.

(m) Impairment of non-financial assets

The carrying amounts of the Partnership's non-financial assets are reviewed at each reporting date to determine whether there is any indication of impairment. Non-financial assets include PP&E, intangible assets and goodwill. For PP&E and intangible assets with definite useful lives, the recoverable amount is estimated when an indication of impairment exists. For goodwill and intangible assets that have indefinite useful lives or that are not yet available for use, the recoverable amount is estimated at least once each year.

3. Significant accounting policies (continued)

(m) Impairment of non-financial assets (continued)

The recoverable amount of an asset or cash-generating unit (CGU) is the greater of its value in use and its fair value less costs to sell. In assessing value in use, the estimated future cash flows are discounted to their present value using an pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. For the purpose of impairment testing, assets that cannot be tested individually are tested as a CGU. CGU's are the smallest group of assets that generate cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets. For the purposes of goodwill impairment testing, goodwill acquired in a business combination is allocated to the CGU, or the group of CGUs, that is expected to benefit from the synergies of the combination. This allocation is subject to an operating segment ceiling test and reflects the lowest level at which that goodwill is monitored for internal reporting purposes.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in comprehensive income. Impairment losses recognized in respect of CGUs are allocated first to reduce the carrying amount of any goodwill allocated to the units, and then to reduce the carrying amount of the assets in the unit or the group of units on a pro rata basis.

An impairment loss in respect of goodwill is not reversed. In respect of other non-financial assets, impairment losses recognized in prior periods are assessed at each reporting date for any indications that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a fundamental change, since the date of impairment, which may improve the financial performance of the non-financial asset. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depreciation or amortization, if no impairment loss had been recognized.

(n) Standards and interpretations not yet applied

A number of new standards, amendments to standards and interpretations of standards have been issued by the International Accounting Standards Board and the International Financial Reporting Interpretations Committee, the application of which is effective for periods beginning on or after January 1, 2022. The Partnership does not expect the implementation of these new accounting pronouncements to have a significant impact on its accounting policies.

4. Use of judgments and estimates

The preparation of the Partnership's financial statements in accordance with IFRS requires management to make judgments in the application of accounting policies, and estimates and assumptions that affect the reported amounts of income, expenses, assets and liabilities as well as the disclosure of contingent assets and liabilities at the date of the financial statements.

(a) Judgments

Information about critical judgments in applying accounting policies that have the most significant effect on the amounts recognized in the financial statements are included in notes:
Note 3(b) - Revenue recognition
Note 3(j) - Provisions

(b) Estimates

The Partnership reviews its estimates and assumptions on an ongoing basis, uses the most current information available and exercises careful judgment in making these estimates and assumptions. Adjustments to previous estimates, which may be material, are recorded in the period in which they become known. Actual results may differ from these estimates.

Assumptions and uncertainties that have a significant risk of resulting in a material adjustment within the next financial year include:

(In thousands of Canadian dollars unless otherwise indicated)

4. Use of judgments and estimates (continued)

(b) Estimates (continued)

Revenues and natural gas purchases

Accounting estimates were made in determining revenue recognized for unbilled customer consumption, which estimates usage using volumes of natural gas entering into the distribution system.

Property, plant and equipment and Intangible assets

Estimating the appropriate economic useful lives of assets requires significant judgment and is generally based on estimates of life characteristics of similar assets.

Fair value measurement

Certain accounting measures such as determining asset impairments and recording financial assets and liabilities use various valuation techniques to determine fair value. Estimates of fair value may be based on readily determinable market values or depreciable replacement cost or discounted cash flow techniques employing estimated future cash flows based on a number of assumptions and using an appropriate discount rate.

5. Novel coronavirus

In March 2020, the global outbreak of the novel coronavirus (COVID-19) was declared a pandemic by the World Health Organization and continues to disrupt business activities including supply chains around the world. In order to manage the impacts of the outbreak, local governmental authorities in Ontario have regularly been monitoring and responding to the emerging situation with maintaining certain travel and business related restrictions. Since the beginning of the pandemic, the Partnership has been operating under its business continuity plan to ensure safety of its employees and customers. In view of the uncertainty caused by the continued persistence of virus infections, the Partnership has deferred its plans for re-integration of the employees back to their permanent work locations. The Partnership is closely monitoring the situation (including advisories from the local governments), and planning to cautiously phase-in the reintegration of its employees back to their permanent work locations when considered safe to do so.

Since the Partnership's operations consist of the provision of essential utility services, the Partnership has not experienced any significant impact of COVID-19 on its operations and financial results. Overall, the COVID -19 pandemic did not result in any material impact on the financial results of the Company for the years ended December 31, 2021 and 2020.

6. Revenues

	2021	2020
Natural gas sales	$ 6,076	$ 4,727
Provision of services	10,355	7,661
	$ 16,431	$ 12,388

Revenue from contracts with customers expected to be recognized in future periods related to performance obligations that are unsatisfied or partially satisfied at the reporting date are as follows:

	2022	2023	2024	2025	2026	2027 and thereafter	Total
Contract liabilities - contributions received from customers and developers[1]	$ 538	$ 538	$ 538	$ 538	$ 538	$ 20,635	$ 23,325
Total	$ 538	$ 538	$ 538	$ 538	$ 538	$ 20,635	$ 23,325

(In thousands of Canadian dollars unless otherwise indicated)

6. Revenues (continued)

1 At December 31, 2021, the Partnership had $23,325 (2020 – $23,917) of deferred revenue recorded in the statements of financial position related to contributions received from customers and developers. Revenue will be recognized in future periods related to this balance, as described in note 3(i), over periods ranging from 10 to 50 years.

The Partnership has numerous contracts with customers for supply of natural gas. The contracts are primarily perpetual with no agreed fixed term and can be terminated at any time either by customer or by the Partnership. The Partnership has also entered into fixed term contracts with some industrial customers. Under the terms of the contracts, in case of termination of these contracts, the Partnership has the right to receive payment for the performance completed to the termination date.

7. Depreciation and amortization

	2021	2020
Depreciation of property, plant and equipment	$ 3,342	$ 1,660
Amortization of intangible assets	113	104
Loss on Disposal of Assets	33	-
	$ 3,488	$ 1,764

8. Finance expenses

	2021	2020
Interest on loans and borrowings	$ 1,482	$ 899
Interest on lease liabilities	1	2
Bank fees	2	19
Other	21	30
Capitalized interest on property, plant and equipment (note 10)	(237)	(531)
	$ 1,269	$ 419

9. Trade and other receivables

	2021	2020
Trade receivables	$ 2,785	$ 4,174
Unbilled revenue	1,181	841
Gross accounts receivable	3,966	5,015
Expected credit loss allowance (note 22)	(49)	(25)
Net trade receivables	3,917	4,990
Short-term note receivable[1]	-	3,271
Net accounts receivable	$ 3,917	$ 8,261

1 Short-term note receivable from EPCOR is unsecured and due on demand. Interest is payable monthly.

Details of the aging of accounts receivables and analysis of the changes in the ECL allowance are provided in note 22.

(In thousands of Canadian dollars unless otherwise indicated)

10. Property, plant and equipment

	Land	Building & hardware	Construction work in progress	Machinery & equipment	Natural gas distribution	Right-of-use assets[1]	Total
Cost							
Balance, beginning of 2021	$ 247	$ 824	$ 7,032	$ 830	$ 90,883	$ 78	$ 99,894
Additions[2]	-	-	24,887	-	-	81	24,968
Transfers into service	11	246	(23,531)	261	23,013	-	-
Disposal and retirements	-	-	-	(178)	-	-	(178)
Balance, end of 2021	258	1,070	8,388	913	113,896	159	124,684
Accumulated depreciation							
Balance, beginning of 2021	-	231	-	167	3,018	49	3,465
Depreciation	-	106	-	111	3,085	40	3,342
Disposal and retirements	-	-	-	(40)	-	-	(40)
Balance, end of 2021	-	337	-	238	6,103	89	6,767
Net book value, end of 2021	$ 258	$ 733	$ 8,388	$ 675	$107,793	$ 70	$117,917

	Land	Building & hardware	Construction work in progress	Machinery & equipment	Natural gas distribution	Right-of-use[1] assets	Total
Cost							
Balance, beginning of 2020	$ 42	$ 541	$ 39,439	$ 388	$ 21,283	$ 78	$ 61,771
Additions	-	-	38,123	-	-	-	38,123
Transfers into service	205	283	(70,530)	442	69,600	-	-
Balance, end of 2020	247	824	7,032	830	90,883	78	99,894
Accumulated depreciation							
Balance, beginning of 2020	-	133	-	77	1,585	10	1,805
Depreciation	-	98	-	90	1,433	39	1,660
Balance, end of 2020	-	231	-	167	3,018	49	3,465
Net book value, end of 2020	$ 247	$ 593	$ 7,032	$ 663	$ 87,865	$ 29	$ 96,429

1 The ROU assets consist of land and buildings (including office spaces).

2 CWIP additions include $391 related to the reclass of amounts recorded in Deferred Revenue at December 31, 2020 that should have been included in Property, Plant and Equipment.

Borrowing costs capitalized during the year ended December 31, 2021, were $237 (2020 - $531) (note 8). The weighted average rate used to determine the borrowing costs eligible for capitalization was 2.45% (2020 - 4.2%).

There are no security charges over the Partnership's property, plant and equipment.

(In thousands of Canadian dollars unless otherwise indicated)

11. Intangible assets and goodwill

	Goodwill	Intangibles Work in Progress	Software	Other rights	Total
Cost					
Balance, beginning of 2021	$ 1,808	$ -	$ 252	$ 1,205	$ 3,264
Investment in intangible assets		87	-	-	87
Transfers into service	-	(66)	66	-	-
Balance, end of 2021	1,808	21	318	1,205	3,352
Accumulated amortization					
Balance, beginning of 2021	-	-	36	258	294
Amortization	-	-	31	82	113
Balance, end of 2021	-	-	67	340	407
Net book value, end of 2021	$ 1,808	$ 21	$ 251	$ 865	$ 2,945

	Goodwill	Intangibles Work in Progress	Software	Other rights	Total
Cost					
Balance, beginning of 2020	$ 1,808	$ 70	$ 100	$ 1,202	$ 3,180
Investment in intangible assets	-	84	-	-	84
Transfers into service	-	(154)	152	2	-
Balance, end of 2020	1,808	-	252	1,204	3,264
Accumulated amortization					
Balance, beginning of 2020	-	-	13	177	190
Amortization	-	-	23	81	104
Balance, end of 2020	-	-	36	258	294
Net book value, end of 2020	$ 1,808	$ -	$ 216	$ 946	$ 2,970

There are no security charges over the Partnership's intangible assets.

For purposes of impairment testing, goodwill acquired through business combination has been allocated to a single CGU, the Aylmer Operations. The most recent review of goodwill was performed in the fourth quarter. Management reviewed conditions since the last review was performed and determined that no circumstances occurred since then to require a revision to the assumptions used in the value in use calculations.

The recoverable amount of the CGU was determined using a discounted cash flow analysis. Forecasted cash flows reflect revenues consistent with OEB methodology of allowing a fair return on prudently placed capital that is recoverable through customer rates. Operating costs reflect historical costs of running the business, adjusted for inflation, and capital-spending forecasts reflect system integrity and capacity needs of utility infrastructure.

Key assumptions used in value-in-use calculations

The future cash flows of the underlying businesses are relatively stable since they relate primarily to ongoing natural gas supply in a rate-regulated environment. In the case of CGUs operating under a rate-regulated environment, revenues are set by the regulators to cover operating costs and to earn a return on the rate base, which is set at the regulator's approved weighted average cost of capital for the underlying utility.

The calculation of value in use for the CGU is most sensitive to the following assumptions:

Discount rates

The after-tax discount rates used were 4.25% (2020 – 4.2%), which were estimated based on the weighted average cost of

(In thousands of Canadian dollars unless otherwise indicated)

11. Intangible assets and goodwill (continued)

capital for the CGU.

Timing of future rate increases

Revenue growth is forecast to continue in concordance with rate base growth. Prudent capital investment in utility infrastructure, to meet customer demand and system integrity needs, may be included in rate base and allowed to earn a fair return by the regulator. Such return on rate base is recovered through customer rates, which drive revenue. In the case of rate-regulated businesses, if future rate filings are delayed then rate increases and increased cash flows from revenues would be affected.

Sensitivity to changes in assumptions

Assumptions have been tested using reasonably possible alternative scenarios. For all scenarios considered, the recoverable value remained above the carrying amount of the CGU.

12. Trade and other payables

	2021	2020
Trade payables	$ 1,336	$ 7,932
Other payables	3,807	6,814
Accrued liabilities	3,796	3,430
Accrued interest	52	32
	$ 8,991	$ 18,208

13. Loans and borrowings

	2021	2020
Short-term note payable to EPCOR[1]	$ 209	$ -
Long-term note payable to EPCOR[2]		
At 3.83%, due in 2047	8,660	8,660
At 2.86%, due in 2050	29,000	29,000
At 3.41%, due in 2051	2,500	-
At 3.37%, due in 2051	12,000	-
Total loans and borrowings	52,369	37,660
Less: current portion	(209)	-
	$ 52,160	$ 37,660

1 Short-term note payable to EPCOR is unsecured and due on demand. Interest is payable monthly at 2.45% per annum.

2 The long-term notes payable to EPCOR are unsecured. Interest on notes is payable semi-annually while principal is due at the end of the term.

14. Deferred revenue

	2021	2020
Balance, beginning of year	$ 23,917	$ 5,703
Contribution received	255	18,357
Contribution adjustment	(391)	-
Revenue recognized	(456)	(143)

(In thousands of Canadian dollars unless otherwise indicated)

		23,325		23,917
Less: current portion		538		384
Balance, end of year	$	22,787	$	23,533

Contributions adjustment relates to the reclass of amounts recorded in Deferred Revenue at December 31, 2020 which should have been included in Property, Plant and Equipment.

15. Provisions

Provisions consist of employee benefits obligations for benefits provided under employee incentive plans.

		2021		2020
Balance, beginning of year	$	96	$	78
Provisions made during the year		165		78
Provisions utilized during the year		(96)		(60)
Balance, end of year	$	165	$	96

All employee benefit provision balances are expected to be utilized within one year.

16. Lease liabilities

The changes in lease liabilities during the year were as follows:

		2021		2020
Balance, beginning of year	$	30	$	69
Lease contracts executed during the year		81		-
Payments during the year		(40)		(39)
Balance, end of year	$	71	$	30

Approximate future payments by the Partnership with respect to its lease liabilities are as follows:

		2021		2020
Within one year	$	41	$	30
After one year but not more than five years		31		-
More than five years		-		-
Unrecognized finance expense		(1)		-
	$	71	$	30

The lease liabilities consist of the Partnership's lease for land and building in Huron-Kinloss, Ontario. In 2019, the Partnership entered into an agreement to lease land and building for its Southern Bruce operations. The agreement, which became effective October 2019, has an initial lease term of 2 years and provides for two successive one-year renewal options that can be excercised 3 months prior to the expiration date of October 15, 2021. The Partnership decided to exercise the option to renew the lease. The amended lease was signed on March 10, 2021 and is scheduled to expire on October 15, 2023.

17. Partnership units

The Partnership is authorized to issue unlimited number of Class A common units without nominal or par value. The units are voting and participate equally in profits, losses and capital distributions of the Partnership.

On November 4, 2016, 1,000 partnership units were issued. The General Partner was issued one unit and the Limited Partner 999 units.

On November 1, 2017, 13,358,556 additional units were issued. The General Partner was allocated an additional 13,359 units and the Limited Partner an additional 13,345,197 units.

On December 31, 2019 and December 16, 2020 the Limited Partner contributed an additional $12,000 and $5,000 respectively. No additional units were issued.

(In thousands of Canadian dollars unless otherwise indicated)

On December 13, 2021 the Limited and General Partner contributed an additional $14,985 and $15 respectively. No additional units were issued.

The General Partner holds 13,360 (2020 – 13,360) Class A common units having capital contribution of $29 (2020 - $14) in the Partnership. It manages the operations of the Aylmer Operations and has a 0.10% (2020 – 0.10%) interest in the profits, losses and capital distributions of the Partnership.

The Limited Partner holds 13,346,196 (2020 – 13,346,196) Class A common units representing a net capital contribution of $45,331 (2020 – $30,346) in the Partnership. The Limited Partner has 99.90% (2020 – 99.90%) interest in the profits, losses and capital distributions of the Partnership.

18. Changes in non-cash working capital

	2021	2020
Trade and other receivables (note 9)	$ 4,344	$ (1,975)
Prepaid expenses	(27)	-
Inventories	(130)	(297)
Trade and other payables (note 12)	(9,217)	9,446
Customer deposits	129	150
Changes in non-cash working capital	$ (4,901)	$ 7,324
Operating activities	$ (5,353)	$ 6,264
Investing activities	452	1,060
	$ (4,901)	$ 7,324

19. Changes in liabilities arising from financing activities:

	Lease liabilities	Short-term loans and borrowings	Long-term loans and borrowings
Balance, beginning of year	$ 30	$ -	$ 37,660
Issued	81	151,749	14,500
Redemptions or repayments	(40)	(151,540)	-
Balance, end of year	$ 71	$ 209	$ 52,160

20. Related party balances and transactions

The Partnership is indirectly 100% owned by EPCOR, which is in turn 100% owned by The City of Edmonton. The Partnership purchases services from EPCOR and its subsidiaries relating to operational and inventory management, administration, health safety & environment, maintenance, repair, utilities, facilities, general plant use, employee costs, executive oversight, legal, finance, treasury, audit, human resources, procurement, public & government affairs, and information technology services pursuant to service agreements. Transactions between the Partnership and its related parties are in the normal course of operations, and are generally based on normal commercial rates, or as agreed to by the parties.

The following summarizes the Partnership's related party transactions with EPCOR and its subsidiaries:

	2021	2020
Statements of Comprehensive Income		
Staff cost and employee benefit expense (a)	$ 1,780	$ 1,644
Other raw materials and operating charges (b)	29	34
Other administrative expenses (c)	2,248	1,878

(In thousands of Canadian dollars unless otherwise indicated)

Finance expenses (d)	1,498	922

20. Related party balances and transactions (continued)

(a) Relates to staff costs and employee benefits expenses paid by EPCOR on behalf of the Partnership.
(b) Relates to expenditures for insurance.
(c) Relates to expenditures for administrative services.
(d) Relates to interest expense on short-term and long-term notes payable to EPCOR.

The following summarizes the Partnership's related party balances with EPCOR and its subsidiaries:

	2021	2020
Statements of Financial Position		
Trade and other receivables (e)	$ 262	$ 3,245
Property, plant and equipment (f)	797	434
Trade and other payables (g)	224	113
Loans and borrowings (e)	52,369	37,660
Provisions (h)	165	96

(e) Relates to short-term and long-term notes receivable to or payable from EPCOR.
(f) Relates to expenditures for information services projects.
(g) Relates to balances payable for administration of services and accrued interest on long-term notes payable to EPCOR.
(h) Relates to provisions for employee benefits.

21. Financial instruments

Classification

The classification of the Partnership's financial instruments at December 31, 2021 and 2020 are summarized as follows:

	Classification			
	Fair value through profit or loss	Fair value through other comprehensive income	Amortized cost	Fair value hierarchy
Measured at amortized cost				
Cash and cash equivalents			X	Level 1
Trade and other receivables			X	Level 3
Trade and other payables			X	Level 3
Loans and borrowings			X	Level 2
Customer deposits			X	Level 3

Fair value

The carrying amounts of cash, trade and other receivables, customer deposits and trade and other payables approximate their fair values due to the short-term nature of these financial instruments.

The carrying amount and fair value of the Partnership's remaining financial instrument are as follows:

	2021		2020	
	Carrying amount	Fair value	Carrying amount	Fair value
Loans and borrowings (note 13)	$ 52,369	$ 51,524	$ 37,660	$ 40,381

21. Financial instruments (continued)

Fair value hierarchy

The financial instruments of the Partnership have been disclosed at fair value using a fair value hierarchy. A Level 1 valuation is determined by unadjusted quoted prices in active markets for identical assets or liabilities. A Level 2 valuation is based upon inputs other than quoted prices included in Level 1 that are observable for the instruments either directly or indirectly. A Level 3 valuation for the assets and liabilities are not based on observable market data.

Loans and borrowings

Short-term loans and borrowings are measured at amortized cost and their carrying value approximate their fair value due to the short-term nature of these financial instruments.

The fair value of the Partnership's long-term loans and borrowings is based on determining a current yield for the Partnership's debt at December 31, 2021 and 2020. This yield is based on an estimated credit spread for the Partnership over the yields of long-term Government of Canada bonds for Canadian dollar loans that have similar maturities to the Partnership's debt.

22. Financial risk management

Overview

The Partnership is exposed to a number of different financial risks arising from business activities and its use of financial instruments, including market risk, credit risk, and liquidity risk. The Partnership's overall risk management process is designed to identify, assess, measure, manage, mitigate and report on business risk which includes financial risk. Enterprise risk management is overseen by the Board of Directors of EPCOR and senior management is responsible for fulfilling objectives, targets, and policies approved by the Board of Directors of EPCOR. EPCOR's Director of Audit and Risk Management provides the Board of Directors of EPCOR with an enterprise risk assessment on a quarterly basis. Risk management strategies, policies, and limits are designed to help ensure the risk exposures are managed within the EPCOR's business objectives and risk tolerance. The Partnership's financial risk management objective is to protect and minimize volatility in earnings and cash flow.

Financial risk management including interest rate risk, liquidity risk and the associated credit risk management is carried out by EPCOR's centralized Treasury function in accordance with applicable policies. The Audit Committee of the Board of Directors of EPCOR, in its oversight role, performs regular and ad-hoc reviews of risk management controls and procedures to help monitor compliance.

Market risk

Market risk is the risk of loss that results from changes in market factors such as energy prices and interest rates. The level of market risk to which the Partnership is exposed at any point in time varies depending on market conditions, expectations of future price or market rate movements and the composition of the Partnership's financial assets and liabilities held. EPCOR's financial exposure management policy is approved by the Board of Directors of EPCOR and the associated procedures and practices are designed to manage the interest rate risk throughout the Partnership.

Interest rate risk

The Partnership is exposed to interest rate risk from the possibility that changes in the interest rates will affect future cash flows or the fair values of its financial instruments. Interest rate risk associated with short-term loans and borrowings is immaterial due to their short-term maturity. At December 31, 2021 and 2020, all long-term loans and borrowings were fixed rate.

Credit risk

Credit risk is the possible financial loss associated with the inability of counterparties to satisfy their contractual obligations to the Partnership, including payment and performance. EPCOR's credit risk management policy is approved by the Board of Directors of EPCOR and the associated procedures and practices are designed to manage the credit risks associated with the various business activities throughout the group including the Partnership. Credit and counterparty risk management procedures and practices generally include assessment of individual counterparty creditworthiness and establishment of exposure limits prior to entering into a transaction with the counterparty. Exposures and concentrations are subsequently monitored and are regularly reported to senior management. Creditworthiness continues to be evaluated after transactions have been initiated, at a minimum, on an annual basis.

The COVID-19 outbreak and resulting measures introduced by various governments and municipalities have resulted in economic slowdown. The economic slowdown together with measures by various governments preventing utility companies from disconnecting customers for non-payment and allowing certain utility customers to defer payments of their utility bills for a limited period, have increased the credit risk of the Partnership, however no material impacts have resulted.

To manage and mitigate credit risk, the Partnership employs various credit mitigation practices such as master netting agreements, pre-payment arrangements from customers and other forms of credit enhancements including cash deposits, parent company guarantees, and bank letters of credit.

*Maximum credit risk exposur*e

The Partnership's maximum credit exposure is represented by the carrying amount of the trade and other receivables balance of $3,917 (2020 – $4,990) (note 9). These carrying amounts do not take into account collateral held. At December 31, 2021, the Partnership held cash deposits of $378 (2020 – $249 cash deposits) as security for certain counterparty accounts receivable.

Credit quality and concentrations

The Partnership is exposed to credit risk on outstanding trade receivables associated with natural gas services to customers. The Partnership's trade receivables are unrated, unsecured and not of investment grade.

Rate-regulated customer credit risk

Credit risk exposure is generally limited to amounts due from residential and commercial customers for natural gas consumed but not yet paid for. The Partnership mitigates credit risk from counterparties by performing credit checks and on higher risk customers, by taking pre-payments or cash deposits.

Trade and other receivables and ECL allowance

Trade and other receivables consist primarily of amounts due from retail customers including residential and commercial customers. The Partnership mitigates these exposures by dealing with creditworthy counterparties and, when appropriate and contractually allowed, obtaining appropriate security from customers.

For retail customers, represented by a diversified customer base, credit losses are generally low and the Partnership provides an allowance for lifetime ECL.

The Partnership calculates the ECL allowance on accounts receivable using a provision matrix approach, which is based on the Partnership's historical credit loss experience and current economic conditions (including forward-looking information) for accounts receivables to estimate the lifetime ECL allowance. The provision matrix specifies fixed provision rates depending on the number of days that a trade receivable is due or past due. The COVID-19 pandemic did not have a significant impact on the Partnership's ECL allowance. The total lifetime ECL allowance at December 31, 2021 is $49 (2020 – $25).

(In thousands of Canadian dollars unless otherwise indicated)

22. Financial risk management (continued)

The gross amount of trade receivables and corresponding ECL is as follows:

December 31, 2021		Gross trade receivables		Expected credit loss allowance		Net trade receivables
Current (a)	$	3,786	$	16	$	3,770
Outstanding 31 to 60 days		155		14		141
Outstanding 61 to 90 days		6		2		4
Outstanding more than 90 days		19		17		2
	$	3,966	$	49	$	3,917

December 31, 2020		Gross trade receivables		Expected credit loss allowance		Net trade receivables
Current (a)	$	4,797	$	4	$	4,793
Outstanding 31 to 60 days		188		2		186
Outstanding 61 to 90 days		11		2		9
Outstanding more than 90 days		19		17		2
	$	5,015	$	25	$	4,990

(a) Current amounts represent trade and other receivables as well as accrued revenues outstanding up to 30 days. Amounts outstanding for more than 30 days are considered past due.

The change in the ECL allowance was as follows:

		2021		2020
Balance, beginning of year	$	25	$	73
Additional allowances created		44		37
Recovery of receivables		1		5
Receivables written off		(22)		(90)
Balance, end of year	$	49	$	25

During the year, the Partnership recognized $44 (2020 – $37) ECL as expense in profit or loss relating to customer amounts that the Partnership determined may not be fully collectable. The lifetime ECL allowance is determined by considering the unique factors of different customer types. Write-offs are determined either by applying specific risk factors to customer groups' aged balances in trade and other receivables or by reviewing material accounts on a case-by-case basis. Reductions in trade and other receivables and the related ECL allowance is recorded when the Partnership has determined that recovery is not possible.

(In thousands of Canadian dollars unless otherwise indicated)

22. Financial risk management (continued)

Liquidity risk

Liquidity risk is the risk that the Partnership will not be able to meet its financial obligations as they become due. The Partnership's liquidity is managed centrally by EPCOR's Treasury function. EPCOR manages liquidity risk through regular monitoring of cash and currency requirements by preparing short-term and long-term cash flow forecasts and by matching the maturity profiles of financial assets and liabilities to identify financing requirements. The financing requirements of the Partnership are addressed through operating cash flows, and if necessary, intercompany financing from EPCOR.

The undiscounted cash flow requirements and contractual maturities of the Partnership's financial liabilities, including interest payments, are as follows:

At December 31, 2021:

	2021	2022	2023	2024	2025	2026 and thereafter	Total contractual cash flows
Trade and other payables[(a)]	$ 8,939	$ -	$ -	$ -	$ -	$ -	$ 8,939
Customer Deposits	378	-	-	-	-	-	378
Loans and borrowings	209	-	-	-	-	52,160	52,369
Interest payments on loans and borrowings	1,650	1,650	1,650	1,650	1,650	39,112	47,362
Lease liabilities	40	31	-	-	-	-	71
	$ 11,216	$ 1,681	$ 1,650	$ 1,650	$ 1,650	$ 91,272	$ 109,119

(a) Excluding accrued interest on loans and borrowings of $52 (2020 – $32).

The Partnership's undiscounted cash flow requirements and contractual maturities in the next twelve months of $11,216 (2020 – $19,616) will be funded from operating cash flows and additional loans and borrowings.

23. Capital management

The Partnership's primary objectives when managing capital is to safeguard the Partnership's ability to continue as a going concern and pay cash distributions to its unit holders. The Partnership manages its capital structure in a manner consistent with the risk characteristics of the underlying assets and in accordance with OEB regulatory decisions.

The Partnership manages capital through regular monitoring of cash requirements by preparing short-term and long-term cash flow forecasts and reviewing monthly financial results. The Partnership matches the maturity profiles of financial assets and liabilities to identify financing requirements to help ensure an adequate amount of liquidity.

The Partnership considers its capital structure to consist of loans and borrowings (including current portion) net of cash and unit holder's equity. The following table represents the Partnership's total capital:

	2021	2020
Loans and borrowings (including current portion) (note 13)	$ 52,369	$ 37,660
Cash	(5)	(6)
Net debt	52,364	37,654
Total equity	40,029	27,893
Total capital	$ 92,393	$ 65,547

To manage or adjust its capital structure, the Partnership can issue new debt, repay existing debt or issue or redeem common units.

24. Commitments and contingencies

The following are the Partnership's commitments and contingencies not otherwise disclosed in these financial statements as at December 31, 2021:

(a) Commitments for the minimum cost of the monthly demand charge from Enbridge regardless of the total volume of gas delivered into the distribution system estimated at $1,355 (2020 – $1,259) annually.

(b) Commitments for the purchase of general administrative and operation services from EPCOR and its subsidiaries are estimated at $2,320 (2020 – $1,517) annually. These estimates are subject to change based on actual activity levels.

(c) Commitments for the purchase of design and construction services from Aecon Construction Group Inc. are estimated at $9,158 (2020 – $19,296) remaining on the contract to construct the Southern Bruce gas distribution infrastructure. The Partnership will require financing from the parent company to settle these commitments.

(In thousands of Canadian dollars unless otherwise indicated)

25. Divisional information

The Partnership operates two divisions that are geographically separated in Southwestern Ontario: Aylmer and Southern Bruce. Divisional information for the reporting period is as follows:

	Aylmer Operations	Southern Bruce Operations	2021 Total
Revenue	$ 13,261	$ 3,170	$ 16,431
Operating expenses:			
Energy purchases	5,795	173	5,968
Staff costs and employee benefits expenses	1,248	532	1,780
Depreciation and amortization (note 7)	1,092	2,396	3,488
Other raw materials and operating charges	2,062	822	2,884
Franchise fees and property taxes	601	271	872
Other administrative expenses	1,530	1,504	3,034
	12,328	5,698	18,026
Operating income (loss)	933	(2,528)	(1,595)
Finance expenses (note 8)	(402)	(867)	(1,269)
Comprehensive income (loss) for the year - all attributable to the Partners	$ 531	$ (3,395)	$ (2,864)

	Aylmer Operations	Southern Bruce Operations	2020 Total
Revenue	$ 11,593	$ 795	$ 12,388
Operating expenses:			
Energy purchases	4,817	13	4,830
Staff costs and employee benefits expenses	1,201	443	1,644
Depreciation and amortization (note 7)	1,030	734	1,764
Other raw materials and operating charges	1,927	424	2,351
Franchise fees and property taxes	615	93	708
Other administrative expenses	1,474	1,485	2,959
	11,064	3,192	14,256
Operating income (loss)	529	(2,397)	(1,868)
Finance expenses (note 8)	(382)	(37)	(419)
Comprehensive income (loss) for the year - all attributable to the Partners	$ 147	$ (2,434)	$ (2,287)

Financial Statements of

EPCOR NATURAL GAS LIMITED PARTNERSHIP

Years ended December 31, 2023 and 2022

INDEPENDENT AUDITOR'S REPORT

To the Board of Directors of
EPCOR Ontario Utilities Inc.

Opinion

We have audited the financial statements of EPCOR Natural Gas Limited Partnership (the Entity), which comprise the statement of financial position as at December 31, 2023, and the statement of comprehensive income, statement of changes in equity and statement of cash flows for the year ended, and notes to the financial statements, including material accounting policy information..

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Entity as at December 31, 2023, and its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards.

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the Auditor's Responsibilities for the Audit of the Financial Statements section of our report. We are independent of the Entity in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada, and we have fulfilled our other ethical responsibilities in accordance with these requirements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Entity's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Entity or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Entity's financial reporting process.

Auditor's Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Entity's internal control.

- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Entity's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Entity to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

Chartered Professional Accountants, Licensed Public Accountants

Barrie, Ontario

Date April 19, 2024

EPCOR NATURAL GAS LIMITED PARTNERSHIP

Statement of Comprehensive Loss
(In thousands of Canadian dollars)

Year ended December 31, 2023 and 2022

	2023	2022
Revenue (note 5)	$ 28,216	$ 24,193
Operating Expenses:		
Energy purchases	13,062	11,928
Staff costs and employee benefits expenses	1,994	1,694
Depreciation and amortization (note 6)	5,727	4,066
Other raw materials and operating charges	3,542	3,555
Franchise fees and property taxes	1,066	957
Other administrative expenses	3,807	3,422
	29,198	25,622
Operating Loss	(982)	(1,429)
Finance expenses (note 7)	(2,987)	(2,093)
Comprehensive loss for the year - all attributable to the Partners	**$** (3,969)	**$** (3,522)

The accompanying notes are an integral part of these financial statements

EPCOR NATURAL GAS LIMITED PARTNERSHIP

Statement of Financial Position
(In thousands of Canadian dollars)

December 31, 2023 and 2022

	2023	2022
ASSETS		
Current assets:		
Cash	$ -	$ 7
Trade and other receivables (note 8)	4,491	4,440
Prepaid expenses	38	25
Inventories	1,772	1,143
	6,301	5,615
Non-current assets:		
Property, plant and equipment (note 9)	145,212	138,877
Intangible assets (note 10)	1,135	1,080
Goodwill (note 10)	1,808	1,808
	148,155	141,765
TOTAL ASSETS	$ 154,456	$ 147,380
LIABILITIES AND EQUITY		
Current liabilities:		
Trade and other payables (note 11)	$ 8,955	$ 10,280
Loans and borrowings (note 12)	13,208	8,550
Customer deposits	386	373
Deferred revenue (note 5 and 13)	667	654
Provisions (note 14)	127	175
Current portion of lease liabilities (note 15)	44	39
	23,387	20,071
Non-current liabilities:		
Loans and borrowings (note 12)	61,160	59,160
Deferred revenue (note 13)	22,125	22,351
Lease liabilities (note 15)	246	291
	83,531	81,802
Total liabilities	106,918	101,873
Equity attributable to the Partners:		
Partnership units (note 16)	60,360	54,360
Deficit	(12,822)	(8,853)
Total equity – attributable to the Partners	47,538	45,507
TOTAL LIABILITIES AND EQUITY	$ 154,456	$ 147,380

Approved on behalf of the partnership,

John Elford
Director, EPCOR Ontario Utilities Inc.

Joe Gysel
Director, EPCOR Ontario Utilities Inc.

The accompanying notes are an integral part of these financial statements

EPCOR NATURAL GAS LIMITED PARTNERSHIP

Statement of Changes in Equity
(In thousands of Canadian dollars)

December 31, 2023 and 2022

	Partnership Units (note 16)	Deficit	Equity attributable to the Partners
Equity at December 31, 2021	$ 45,360	$ (5,331)	$ 40,029
Equity contribution from the Partners (note 16)	9,000	-	9,000
Comprehensive loss for the year	-	(3,522)	(3,522)
Equity at December 31, 2022	$ 54,360	$ (8,853)	$ 45,507
Equity contribution from the Partners (note 16)	6,000	-	6,000
Comprehensive loss for the year	-	(3,969)	(3,969)
Equity at December 31, 2023	$ 60,360	$ (12,822)	$ 47,538

The accompanying notes are an integral part of these financial statements

EPCOR NATURAL GAS LIMITED PARTNERSHIP

Statement of Cash Flows
(In thousands of Canadian dollars)

Year ended December 31, 2023 and 2022

	2023	2022
Cash flows from (used in) operating activities:		
Comprehensive loss for the year	$ (3,969)	$ (3,522)
Reconciliation of comprehensive loss for the year to cash from (used in) operating activities:		
Interest paid (net)	(2,979)	(2,093)
Finance expenses (net)	2,987	2,093
Depreciation and amortization (note 6)	5,722	4,073
(Gain) Loss on disposal of property, plant and equipment	5	(7)
Contribution received (note 13)	447	265
Deferred revenue recognized (note 13)	(659)	(585)
Change in employee benefits provisions (note 14)	(48)	10
Net cash flows from operating activities before non-cash operating working capital changes	1,506	234
Changes in non-cash operating working capital (note 17)	(1,044)	123
Net cash flows from operating activities	462	357
Cash flows from (used in) investing activities:		
Acquisition or construction of property, plant and equipment (note 9)	(11,933)	(24,621)
Acquisition of intangible assets (note 10)	(179)	(56)
Proceeds from sale of property, plant and equipment	-	18
Change in non-cash investing working capital (note 17)	(975)	14
Net cash flows used in investing activities	(13,087)	(24,645)
Cash flows from (used in) financing activities:		
Net (repayment) issuance of short-term loans and borrowings (note 18)	4,658	8,341
Proceeds from issuance of long-term loans and borrowings (note 18)	2,000	7,000
Payments of lease liabilities (note 15)	(40)	(51)
Equity contribution from the Partners (note 16)	6,000	9,000
Net cash flows from financing activities	12,618	24,290
Change in cash and cash equivalents	(7)	2
Cash and cash equivalents, beginning of year	7	5
Cash and cash equivalents, end of year	$ -	$ 7

The accompanying notes are an integral part of these financial statements

1. Description of business

(a) Nature of operations

EPCOR Natural Gas Limited Partnership (the Partnership) provides natural gas distribution service through its general partner EPCOR Ontario Utilities Inc. (the General Partner or EOUI) and operates within Southwestern Ontario under franchise agreements that are approved by the Ontario Energy Board (OEB).

The Partnership was formed on November 4, 2016 pursuant to a Certificate of Limited Partnership and a limited partnership agreement entered into between the General Partner and EPCOR Commercial Services Inc. (the Limited Partner) dated as of November 4, 2016 and operates in Ontario with its registered head office located at 77 King Street West, Suite 400, Toronto, Ontario M5K 0A1.

The Partnership is a limited partnership registered in Canada and is managed by the General Partner. Although the General Partner holds legal title to the assets, the Partnership is the beneficial owner and assumes all the risks and rewards of the assets.

The Partnership is indirectly 100% controlled by EPCOR Utilities Inc. (EPCOR).

The Partnership operates two divisions that are geographically separated in Southwestern Ontario, referred to respectively as Aylmer (Aylmer Operations) and Southern Bruce (Southern Bruce Operations). The EPCOR Natural Gas Limited Partnership Financial Statements present the financial position, comprehensive income, change in equity and cash flows of both divisions.

(b) Rate regulation

The Partnership's Operations are regulated by the OEB pursuant to *The Ontario Energy Board Act* (Ontario), *The Energy Act* (Ontario) and regulations made under those statutes. The OEB administers these acts and regulations regarding tariffs, rates, construction, financing, operations, accounting and service area. Revenue rate schedules are approved periodically by the OEB and are designed to permit a fair and reasonable return to the Partnership on the utility investment. Realization of the allowed rate of return is subject to actual operating conditions experienced during the year.

Regulatory risk is the risk that the Province and its regulator, the OEB, could establish a regulatory regime that imposes conditions that restrict the natural gas distribution business from achieving an acceptable rate of return that permits financial sustainability of its operations, including the recovery of expenses incurred for the benefit of other market participants in the natural gas industry such as transition costs and other regulatory assets. All requests for change in natural gas distribution charges require the approval of the OEB.

Regulatory developments in Ontario's natural gas industry, including current and possible future consultations between the OEB and interested stakeholders, may affect distribution rates and other permitted recoveries in the future. The Aylmer Operations are subject to a cost of service regulatory mechanism under which the OEB establishes the revenues required (i) to recover the forecast operating costs, including depreciation and amortization and income taxes, of providing the regulated service, and (ii) to provide a fair and reasonable return on utility investment, or rate base. As actual operating conditions may vary from forecast, actual returns achieved can differ from approved returns. The current cost of service rates are applicable for years 2020 through 2024. The Aylmer Operations' rates change annually based on a formula comprised of the following factors: inflation factor, productivity factor, and stretch factor. In addition and in limited circumstances, the Aylmer Operations has the ability to apply for supplementary funding for certain capital additions.

The Southern Bruce Operations are subject to a cumulative revenue regulatory mechanism under which the OEB establishes the revenues for a 10-year rate stability period. Southern Bruce Operations' rate stability period ends in December 2028. The Southern Bruce Operations' rates change annually based on a formula comprised of the following factors: inflation factor and stabilization factor.

The Partnership did not adopt IFRS 14 – *Regulatory Deferral Accounts* during the Partnership's initial adoption of IFRS.

2. Basis of presentation

(a) Statement of compliance

These financial statements have been prepared by management in accordance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board and Interpretations of the International Financial Reporting Interpretations Committee, and effective on December 31, 2023 and 2022. These financial statements were approved and authorized for issue by the Board of Directors of EOUI on April 19, 2024.

(b) Basis of measurement

The Partnership's financial statements are prepared on the historical cost basis.

(c) Functional and presentation currency

These financial statements are presented in Canadian dollars and all rounded to the nearest thousand dollars, except where otherwise stated.

3. Material accounting policy information

The accounting policies set out below have been applied consistently to all years presented in these financial statements unless otherwise indicated.

(a) Changes in material accounting policies

The Partnership has adopted the amendments to IAS 1 - *Presentation of financial statements* to disclose material accounting policy information rather than significant accounting policy information, effective for annual periods beginning on or after January 1, 2023. The definition of material that management has used to judgmentally determine disclosure is that information is material if, when considered with other information included in these financial statements, it could influence decisions users make on the basis of financial information. Management has determined that the capitalized borrowing costs and lease accounting policy notes are not material for disclosure.

(b) Revenue recognition

The Partnership recognizes revenue when it transfers control over a promised good or service, a performance obligation under the contract, to a customer and where the Partnership is entitled to consideration resulting from completion of the performance obligation. Depending on the terms of the contract with the customer, revenue recognition can occur at a point in time or over time. When a performance obligation is satisfied, revenue is measured at the transaction price that is allocated to that performance obligation. For contracts where non-cash consideration is received, revenue is recognized and measured at the fair value of the non-cash consideration.

Customer contracts may include the transfer of multiple goods and services. Where the Partnership determines that the multiple goods and services are not distinct performance obligations, they are treated as single performance obligation.

Revenues are classified as natural gas sales and provision of services depending on the nature of each distinct performance obligation.

Contract costs for obtaining a customer contract are expensed as incurred unless they create an asset related to future contract activity that the Partnership expects to recover.

Significant judgement may be required to determine the number of distinct performance obligations within a contract and the allocation of transaction price to multiple performance obligations in a contract, and to determine whether the Partnership acts as a principal or agent for certain performance obligations. When multiple performance obligations are identified in a contract, the transaction price is allocated based on the stand-alone selling price of each performance obligation. If stand-alone selling price is not observable, the Partnership estimates the stand-alone selling price for each distinct performance obligation based on the related expected cost plus margin. The Partnership is acting as a principal when the Partnership controls the goods or services before transfer to the customer. The Partnership is acting as an agent when it is obliged to arrange for the provision of the goods and services by another party, that are not controlled by the Partnership before transfer to the customer. When the Partnership acts as an agent, the revenue is recognized

3. Material accounting policies (continued)

(b) Revenue recognition (continued)

net of any related costs incurred.

The Partnership's principal sources of revenue and methods applied to the recognition of these revenues in these financial statements are as follows:

Natural gas sales

The contracts with customers for the supply of natural gas consist primarily of perpetual contracts that are effective until terminated by the customer or the Partnership. The Partnership also has entered into fixed term contracts with some industrial customers to deliver gas over the specified term of the contract. The Partnership provides a series of distinct goods, which are simultaneously received and consumed by the customers. Each of the performance obligations is satisfied over time using the output method for recognition of revenue, i.e. the units of each good supplied to the customer.

Revenues are calculated based on the customer's usage of the goods during the period, at the applicable rates as per the terms of the respective contracts. Customers are generally billed on a monthly basis and payment is generally due within 30 days of billing the customer.

Provision of services

The contracts with customers for each of natural gas transmission and distribution services consist primarily of perpetual contracts that are effective until terminated by the customer or the Partnership. The Partnership has also entered into fixed term contracts with some industrial customers to deliver gas over the specified term of the contract. The Partnership provides a series of distinct services, which are simultaneously received and consumed by the customers. Each of the performance obligations is satisfied over time using the output method for recognition of revenue, i.e. quantifiable services rendered to the customer.

Revenues are calculated based on the services provided to the customer during the period, at the applicable rates as per the terms of the respective contracts. These revenues include an estimate of the value of services provided to the customers in the reporting period and billed subsequent to the reporting period. Customers are billed generally within a month and payment is generally due within 30 days of billing the customer.

(c) Income tax

As a limited partnership, the Partnership is not taxed at the entity level under the Canadian Income Tax Act. All income tax consequences of its operations are borne by its Partners, on a pro rata basis, in proportion to their interest in the Partnership.

(d) Inventories

Small parts and other consumables, the majority of which are consumed by the Partnership in the provision of its goods and services to customers, and natural gas inventories are valued at the lower of cost and net realizable value. Cost includes the purchase price, transportation costs and other costs to bring the inventories to their present location and condition. The costs of inventory items that are interchangeable are determined on an average cost basis. For inventory items that are not interchangeable, cost is assigned using specific identification of their individual costs. Net realizable value is the estimated selling price in the ordinary course of business, less the estimated costs of completion and the estimated costs necessary to make the sale. Previous write-downs of inventories from cost to net realizable value can be fully or partially reversed if supported by economic circumstances. The Partnership estimates the value of inventory that is expected to be used in the construction of property, plant and equipment (PP&E) and reports this value as construction work in progress under PP&E.

(e) Property, plant and equipment

PP&E are recorded at cost, net of accumulated depreciation and accumulated impairment losses, if any.

3. Material accounting policies (continued)

(e) Property, plant and equipment (continued)

Cost includes contracted services, materials, direct labor and directly attributable overhead costs on qualifying assets. Where parts of an item of PP&E have different estimated useful lives, they are accounted for as separate items (major components) of PP&E.

The cost of major inspections and maintenance is recognized in the carrying amount of the item if the asset recognition criteria are satisfied. The carrying amount of a replaced part is derecognized. The costs of day-to-day servicing are expensed as incurred. The cost of a group of PP&E acquired in a transaction, including those acquired in a business combination, is allocated to the individual assets acquired based on their fair value.

Depreciation of cost less residual value is charged on a straight-line basis over the estimated useful lives of items of each depreciable component of PP&E, from the date they are available for use, as this most closely reflects the expected usage of the assets. Land and construction work in progress are not depreciated. Estimating the appropriate useful lives of assets requires judgment and is generally based on estimates of life characteristics of similar assets. The estimated useful lives, methods of depreciation and residual values are reviewed annually with any changes adopted on a prospective basis.

(f) Property, plant and equipment (continued)

The ranges of estimated useful lives for PP&E assets used are as follows:

Building and hardware	2 – 52 years
Machinery and equipment	6 – 31 years
Natural Gas distribution	6 – 51 years
Right-of-use assets	7 – 10 years

Gains or losses on the disposal of PP&E are determined as the difference between the net disposal proceeds and the carrying amount at the date of disposal.

(g) Intangible assets

Intangible assets with finite lives are stated at cost, net of accumulated amortization and impairment losses, if any. The cost of a group of intangible assets acquired in a transaction, including those acquired in a business combination that meet the specified criteria for recognition apart from goodwill, is allocated to the individual assets acquired based on their relative fair value.

The cost of intangible software includes the cost of license acquisitions, contracted services, materials, direct labor, and directly attributable overhead costs on qualifying assets.

Other rights represent the costs to acquire Franchise rights. Other rights are recorded at cost at the date of acquisition. Subsequent expenditures are capitalized only when it increases the future economic benefit in the specific asset to which it relates.

Amortization of the cost of finite life intangible assets is recognized on a straight-line basis over the estimated economic useful lives of the assets, from the date they are available for use, as this most closely reflects the expected usage of the asset. Work in progress is not amortized. The estimated economic useful lives and methods of amortization are reviewed annually with any changes adopted on a prospective basis.

The estimated economic useful lives for intangible assets with finite lives are as follows:

Software	10 years
Other rights	20 years

Gains or losses on the disposal of intangible assets are determined as the difference between the net disposal proceeds and the carrying amount at the date of disposal.

3. Material accounting policies (continued)

(h) Deferred revenue

Certain assets may be contributed by customers or constructed using non-refundable cash contributions from customers. Non-refundable customer contributions received towards construction or acquisition of an item of PP&E, which are used to provide ongoing goods or services to these customers, are recorded as deferred revenue. Deferred revenue is initially recorded at the fair value of contributed assets, or the amount of cash contributions received, and is recognized as revenue on a straight-line basis over the shorter of estimated lives of the respective contracts with the customers or the useful life of the related asset. Where contracts with customers are perpetual and the related contributed asset is used to provide ongoing goods or services to customers, the life of the contract is estimated to be equivalent to the useful life of the asset to which the contribution relates.

Certain assets are acquired or constructed using non-refundable government grants. Government grants are recorded as deferred revenue and are recognized as revenue on a straight-line basis over the estimated useful lives of the assets to which they relate.

(i) Provisions

A provision is recognized if, as a result of a past event, the Partnership has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability. The increase in the provision due to the passage of time is recognized as a finance expense over the estimated period until settlement of the obligation.

(j) Non-derivative financial instruments

Financial assets and financial liabilities are identified and classified as measured at amortized cost.

Financial assets and financial liabilities are presented on a net basis when the Partnership has a legally enforceable right to offset the recognized amounts and intends to settle on a net basis or to realize the asset and settle the liability simultaneously.

Recognition and Measurement

Cash and trade and other receivables are classified as financial assets measured at amortized cost.

These financial assets are recognized initially at fair value plus directly attributable transaction costs, if any. After initial recognition, they are measured at amortized cost using the effective interest method less any impairment as described in note 3(l). The effective interest method calculates the amortized cost of a financial asset and allocates the finance income over the term of the financial asset using an effective interest rate. The effective interest rate is the rate that discounts estimated future cash receipts through the expected life of the financial asset, or a shorter period when appropriate, to the gross carrying amount of the financial asset.

The Partnership's trade and other payables, customer deposits and loans and borrowings are classified as financial liabilities measured at amortized cost and are recognized on the date at which the Partnership becomes a party to the contractual arrangement. Financial liabilities are initially recognized at fair value, plus directly attributable transaction costs, if any. Subsequently, these liabilities are measured at amortized cost using the effective interest rate method.

Derecognition

Financial liabilities are derecognized when the contractual obligations are discharged, cancelled or expire.

(k) Impairment of financial assets

The Partnership uses the "expected credit loss" (ECL) model for calculating impairment and recognizes ECL as a loss allowance for financial assets measured at amortized cost.

For trade receivables without a significant financing component, the Partnership applies the simplified approach and

3. Material accounting policies (continued)

(k) Impairment of financial assets (continued)

uses a provision matrix that is based on the Partnership's historical credit loss experience, current market conditions and forward-looking information, to estimate and recognize the lifetime ECL. Trade and other receivables that are not assessed for impairment individually are assessed for impairment on a collective basis taking into consideration the unique risk factors associated with each customer group.

(l) Impairment of non-financial assets

The carrying amounts of the Partnership's non-financial assets are reviewed at each reporting date to determine whether there is any indication of impairment. Non-financial assets include PP&E, intangible assets and goodwill. For PP&E and intangible assets with definite useful lives, the recoverable amount is estimated when an indication of impairment exists. For goodwill and intangible assets that have indefinite useful lives or that are not yet available for use, the recoverable amount is estimated at least once each year.

The recoverable amount of an asset or cash-generating unit (CGU) is the greater of its value in use and its fair value less costs to sell. In assessing value in use, the estimated future cash flows are discounted to their present value using an pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. For the purpose of impairment testing, assets that cannot be tested individually are tested as a CGU. CGU's are the smallest group of assets that generate cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets. For the purposes of goodwill impairment testing, goodwill acquired in a business combination is allocated to the CGU, or the group of CGUs, that is expected to benefit from the synergies of the combination. This allocation is subject to an operating segment ceiling test and reflects the lowest level at which that goodwill is monitored for internal reporting purposes.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in comprehensive income. Impairment losses recognized in respect of CGUs are allocated first to reduce the carrying amount of any goodwill allocated to the units, and then to reduce the carrying amount of the assets in the unit or the group of units on a pro rata basis.

An impairment loss in respect of goodwill is not reversed. In respect of other non-financial assets, impairment losses recognized in prior periods are assessed at each reporting date for any indications that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a fundamental change, since the date of impairment, which may improve the financial performance of the non-financial asset. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depreciation or amortization, if no impairment loss had been recognized.

(m) Standards and interpretations not yet applied

A number of new standards, amendments to standards and interpretations of standards have been issued by the International Accounting Standards Board and the International Financial Reporting Interpretations Committee, the application of which is effective for periods beginning on or after January 1, 2024. The Partnership does not expect the implementation of these new accounting pronouncements to have a significant impact on its accounting policies.

3. Material accounting policies (continued)

(n) Standards, amendments and interpretation not yet effective

There are a number of standards, amendments to standards, and interpretations which have been issued by the IASB that are effective in future accounting periods that the company has decided not to adopt early.

The following amendments are effective for the period beginning January 1 2024:

• IAS 7 Statement of Cash Flows (Amendment - Supplier Finance Arrangements); and

• IAS 1 Presentation of Financial Statements (Amendment - Non-current Liabilities with Covenants)

The company is currently assessing the impact of these new accounting standards and amendments.

The company does not expect any other standards issued by the IASB, but not yet effective, to have a material impact on the company.

4. Use of judgments and estimates

The preparation of the Partnership's financial statements in accordance with IFRS requires management to make judgments in the application of accounting policies, and estimates and assumptions that affect the reported amounts of income, expenses, assets and liabilities as well as the disclosure of contingent assets and liabilities at the date of the financial statements.

(a) Judgments

Information about critical judgments in applying accounting policies that have the most significant effect on the amounts recognized in the financial statements are included in notes:
Note 3(b) - Revenue recognition
Note 3(j) - Provisions

(b) Estimates

The Partnership reviews its estimates and assumptions on an ongoing basis, uses the most current information available and exercises careful judgment in making these estimates and assumptions. Adjustments to previous estimates, which may be material, are recorded in the period in which they become known. Actual results may differ from these estimates.

Assumptions and uncertainties that have a significant risk of resulting in a material adjustment within the next financial year include:

Revenues and natural gas purchases

Accounting estimates were made in determining revenue recognized for unbilled customer consumption, which estimates usage using volumes of natural gas entering into the distribution system.

Property, plant and equipment and Intangible assets

Estimating the appropriate economic useful lives of assets requires significant judgment and is generally based on estimates of life characteristics of similar assets.

Fair value measurement

Certain accounting measures such as determining asset impairments and recording financial assets and liabilities use various valuation techniques to determine fair value. Estimates of fair value may be based on readily determinable market values or depreciable replacement cost or discounted cash flow techniques employing estimated future cash flows based on a number of assumptions and using an appropriate discount rate.

(In thousands of Canadian dollars unless otherwise indicated)

5. Revenues

	2023	2022
Natural gas sales	$ 13,329	$ 10,875
Provision of services	14,887	13,318
	$ 28,216	$ 24,193

Revenue from contracts with customers expected to be recognized in future periods related to performance obligations that are unsatisfied or partially satisfied at the reporting date are as follows:

	2024	2025	2026	2027	2028	2029 and thereafter	Total
Contract liabilities - contributions received from customers and developers[1]	$ 667	$ 667	$ 667	$ 667	$ 667	$ 19,457	$ 22,792
Total	$ 667	$ 667	$ 667	$ 667	$ 667	$ 19,457	$ 22,792

1 At December 31, 2023, the Partnership had $22,792 (2022 – $23,005) of deferred revenue recorded in the statements of financial position related to contributions received from customers and developers. Revenue will be recognized in future periods related to this balance, as described in note 3(i), over periods ranging from 10 to 50 years.

The Partnership has various contracts with customers for supply of natural gas. The contracts are primarily perpetual with no agreed fixed term and can be terminated at any time either by customer or by the Partnership. The Partnership has also entered into fixed term contracts with some industrial customers. Under the terms of the contracts, in case of termination of these contracts, the Partnership has the right to receive payment for the performance completed to the termination date.

6. Depreciation and amortization

	2023	2022
Depreciation of property, plant and equipment	$ 4,671	$ 3,960
Amortization of intangible assets	124	113
(Gain) Loss on Disposal of Assets	5	(7)
Cancelled project amortization	927	-
	$ 5,727	$ 4,066

7. Finance expenses

	2023	2022
Interest on loans and borrowings	$ 2,929	$ 2,082
Interest on lease liabilities	17	1
Other	41	52
Capitalized interest on property, plant and equipment (note 9)	-	(42)
	$ 2,987	$ 2,093

(In thousands of Canadian dollars unless otherwise indicated)

8. Trade and other receivables

		2023		2022
Trade receivables	$	2,741	$	2,369
Unbilled revenue		1,971		2,171
Gross accounts receivable		4,712		4,540
Expected credit loss allowance (note 22)		(221)		(100)
Net trade receivables		4,491		4,440
Net accounts receivable	$	4,491	$	4,440

Details of the aging of accounts receivables and analysis of the changes in the expected credit loss allowance are provided in note 22.

9. Property, plant and equipment

	Land	Building & hardware	Construction work in progress	Machinery & equipment	Natural gas distribution	Right-of-use assets[1]	Total
Cost							
Balance, beginning of 2023	$ 258	$ 1,123	$ 4,333	$ 1,136	$ 142,260	$ 469	$ 149,579
Additions	-	-	11,933	-	-	-	11,933
Transfers into service	-	108	(13,451)	160	13,183	-	-
Disposal and retirements	-	-	(927)	-	-	-	(927)
Balance, end of 2023	258	1,231	1,888	1,296	155,443	469	160,585
Accumulated depreciation							
Balance, beginning of 2023	-	413	-	334	9,825	130	10,702
Depreciation	-	91	-	134	4,416	30	4,671
Disposal and retirements	-	-	-	-	-	-	-
Balance, end of 2023	-	504	-	468	14,241	160	15,373
Net book value, end of 2023	$ 258	$ 727	$ 1,888	$ 828	$141,202	$ 309	$ 145,212

(In thousands of Canadian dollars unless otherwise indicated)

9. Property, plant and equipment (continued)

	Land	Building & hardware	Construction work in progress	Machinery & equipment	Natural gas distribution	Right-of-use[1] assets	Total
Cost							
Balance, beginning of 2022	$ 258	$ 1,070	$ 8,388	$ 913	$ 113,896	$ 159	$ 124,684
Additions	-	-	24,562	-	59	310	24,931
Transfers into service	-	53	(28,617)	259	28,305	-	-
Disposal and retirements	-	-	-	(36)	-	-	(36)
Balance, end of 2022	258	1,123	4,333	1,136	142,260	469	149,579
Accumulated depreciation							
Balance, beginning of 2022	-	337	-	238	6,103	89	6,767
Depreciation	-	76	-	121	3,722	41	3,960
Disposal and retirements	-	-	-	(25)	-	-	(25)
Balance, end of 2022	-	413	-	334	9,825	130	10,702
Net book value, end of 2022	$ 258	$ 710	$ 4,333	$ 802	$ 132,435	$ 339	$ 138,877

1 The ROU assets consist of a trailer and buildings (including office spaces).

Borrowing costs capitalized during the year ended December 31, 2023, were $nil (2022 - $42) (note 7). The weighted average rate used to determine the borrowing costs eligible for capitalization was 5.95% (2022 - 2.45%).

There are no security charges over the Partnership's property, plant and equipment.

(In thousands of Canadian dollars unless otherwise indicated)

10. Intangible assets and goodwill

	Goodwill	Intangibles Work in Progress	Software	Other rights	Total
Cost					
Balance, beginning of 2023	$ 1,808	$ 21	$ 374	$ 1,205	$ 3,408
Investment in intangible assets		179	-	-	179
Transfers into service	-	(200)	124	76	-
Balance, end of 2023	1,808	-	498	1,281	3,587
Accumulated amortization					
Balance, beginning of 2023	-	-	98	422	520
Amortization	-	-	41	83	124
Balance, end of 2023	-	-	139	505	644
Net book value, end of 2023	$ 1,808	$ -	$ 359	$ 776	$ 2,943

	Goodwill	Intangibles Work in Progress	Software	Other rights	Total
Cost					
Balance, beginning of 2022	$ 1,808	$ 21	$ 318	$ 1,205	$ 3,352
Investment in intangible assets	-	56	-	-	56
Transfers into service	-	(56)	56	-	-
Balance, end of 2022	1,808	21	374	1,205	3,408
Accumulated amortization					
Balance, beginning of 2022	-	-	67	340	407
Amortization	-	-	31	82	113
Balance, end of 2022	-	-	98	422	520
Net book value, end of 2022	$ 1,808	$ 21	$ 276	$ 783	$ 2,888

There are no security charges over the Partnership's intangible assets.

For purposes of impairment testing, goodwill acquired through business combination has been allocated to a single CGU, the Aylmer Operations. The most recent review of goodwill was performed in the fourth quarter. Management reviewed conditions since the last review was performed and determined that no circumstances occurred since then to require a revision to the assumptions used in the value in use calculations.

The recoverable amount of the CGU was determined using a discounted cash flow analysis. Forecasted cash flows reflect revenues consistent with OEB methodology of allowing a fair return on prudently placed capital that is recoverable through customer rates. Operating costs reflect historical costs of running the business, adjusted for inflation, and capital-spending forecasts reflect system integrity and capacity needs of utility infrastructure.

Key assumptions used in value-in-use calculations

The future cash flows of the underlying businesses are relatively stable since they relate primarily to ongoing natural gas supply in a rate-regulated environment. In the case of CGUs operating under a rate-regulated environment, revenues are set by the regulators to cover operating costs and to earn a return on the rate base, which is set at the regulator's approved weighted average cost of capital for the underlying utility.

The calculation of value in use for the CGU is most sensitive to the following assumptions:

(In thousands of Canadian dollars unless otherwise indicated)

10. Intangible assets and goodwill (continued)

Discount rates

The after-tax discount rates used were 5.34% (2022 – 5.25%) which were estimated based on the weighted average cost of capital for the CGU.

Timing of future rate increases

Revenue growth is forecast to continue in concordance with rate base growth. Prudent capital investment in utility infrastructure, to meet customer demand and system integrity needs, may be included in rate base and allowed to earn a fair return by the regulator. Such return on rate base is recovered through customer rates, which drive revenue. In the case of rate-regulated businesses, if future rate filings are delayed then rate increases and increased cash flows from revenues would be affected.

Sensitivity to changes in assumptions

Assumptions have been tested using reasonably possible alternative scenarios. For all scenarios considered, the recoverable value remained above the carrying amount of the CGU.

11. Trade and other payables

	2023	2022
Trade payables	$ 1,027	$ 1,047
Other payables	4,269	4,019
Accrued liabilities	3,576	5,139
Accrued interest	83	75
	$ 8,955	$ 10,280

12. Loans and borrowings

	2023	2022
Short-term note payable to EPCOR[1]	$ 13,208	$ 8,550
Long-term note payable to EPCOR[2]		
At 3.83%, due in 2047	8,660	8,660
At 2.86%, due in 2050	29,000	29,000
At 3.41%, due in 2051	2,500	2,500
At 3.37%, due in 2051	12,000	12,000
At 4.80%, due in 2052	7,000	7,000
At 5.04%, due in 2053	2,000	-
Total loans and borrowings	74,368	67,710
Less: current portion	(13,208)	(8,550)
	$ 61,160	$ 59,160

1 Short-term note payable to EPCOR is unsecured and due on demand. Interest is payable monthly at 6.91% per annum.

2 The long-term notes payable to EPCOR are unsecured. Interest on notes is payable semi-annually while principal is due at the end of the term.

(In thousands of Canadian dollars unless otherwise indicated)

13. Deferred revenue

	2023	2022
Balance, beginning of year	$ 23,004	$ 23,325
Contributions received	447	265
Revenue recognized	(659)	(585)
	22,792	23,005
Less: current portion	667	654
Balance, end of year	$ 22,125	$ 22,351

14. Provisions

Provisions consist of employee benefits obligations for benefits provided under employee incentive plans.

	2023	2022
Balance, beginning of year	$ 175	$ 165
Provisions made during the year	128	175
Provisions utilized during the year	(176)	(165)
Balance, end of year	$ 127	$ 175

All employee benefit provision balances are expected to be utilized within one year.

15. Lease liabilities

The changes in lease liabilities during the year were as follows:

	2023	2022
Balance, beginning of year	$ 330	$ 71
Lease contracts executed during the year	-	310
Payments during the year	(40)	(51)
Balance, end of year	$ 290	$ 330

Approximate future payments by the Partnership with respect to its lease liabilities are as follows:

	2023	2022
Within one year	$ 59	$ 56
After one year but not more than five years	279	295
More than five years	-	44
Unrecognized finance expense	(48)	(65)
	$ 290	$ 330

The lease liabilities consist of the Partnership's lease for land and building in Huron-Kinloss, Ontario. In 2019, the Partnership entered into an agreement to lease land and building for its Southern Bruce operations. The agreement, which became effective October 2019, has an initial lease term of 2 years and provides for two successive one-year renewal options that can be exercised 3 months prior to the expiration date of October 2021. The Partnership decided to exercise the option to renew the lease. The amended lease was signed on March 2021, and is scheduled to expire on October 2023. A second amendment was signed in December 2022, to extend the term of the agreement with an additional 6 years, and is scheduled to expire October 2029.

(In thousands of Canadian dollars unless otherwise indicated)

16. Partnership units

The Partnership is authorized to issue unlimited number of Class A common units without nominal or par value. The units are voting and participate equally in profits, losses and capital distributions of the Partnership.

During 2023 the Limited and General Partner contributed an additional $5,994 (2022 - $8,991) and $6 (2022 - $9) respectively. No additional units were issued.

The General Partner holds 13,360 (2022 – 13,360) Class A common units having capital contribution of $43 (2022 - $37) in the Partnership. It manages the Aylmer and Southern Bruce operations and has a 0.10% (2022 – 0.10%) interest in the profits, losses and capital distribution of the Partnership.

The Limited Partner holds 13,346,196 (2022 – 13,346,196) Class A common units representing a net capital contribution of $60,317 (2022 – $54,323) in the Partnership. The Limited Partner has 99.90% (2022 – 99.90%) interest in the profits, losses and capital distributions of the Partnership.

17. Changes in non-cash working capital

	2023	2022
Trade and other receivables (note 8)	$ (51)	$ (523)
Prepaid expenses	(13)	4
Inventories	(629)	(628)
Trade and other payables	(1,339)	1,289
Customer deposits	13	(5)
Changes in non-cash working capital	$ (2,019)	$ 137
Operating activities	$ (1,044)	$ 123
Investing activities	(975)	14
	$ (2,019)	$ 137

18. Changes in liabilities arising from financing activities:

	Lease liabilities	Short-term loans and borrowings	Long-term loans and borrowings
Balance, beginning of year	$ 330	$ 8,550	$ 59,160
Issued	-	172,151	2,000
Redemptions or repayments	(40)	(167,493)	-
Balance, end of year	$ 290	$ 13,208	$ 61,160

(In thousands of Canadian dollars unless otherwise indicated)

19. Related party balances and transactions

The Partnership is indirectly 100% owned by EPCOR, which is in turn 100% owned by The City of Edmonton. The Partnership purchases services from EPCOR and its subsidiaries relating to operational and inventory management, administration, health safety & environment, maintenance, repair, utilities, facilities, general plant use, employee costs, executive oversight, legal, finance, treasury, audit, human resources, procurement, public & government affairs, and information technology services pursuant to service agreements. Transactions between the Partnership and its related parties are in the normal course of operations, and are generally based on normal commercial rates, or as agreed to by the parties.

The following summarizes the Partnership's related party transactions with EPCOR and its subsidiaries:

	2023	2022
Statements of Comprehensive Income		
Staff cost and employee benefit expense (a)	$ 1,996	$ 1,694
Other raw materials and operating charges (b)	23	73
Other administrative expenses (c)	2,718	2,411
Finance expenses (d)	2,966	2,110

(a) Relates to staff costs and employee benefits expenses paid by EPCOR on behalf of the Partnership.
(b) Relates to expenditures for insurance.
(c) Relates to expenditures for administrative services.
(d) Relates to interest expense on short-term and long-term notes payable to EPCOR.

The following summarizes the Partnership's related party balances with EPCOR and its subsidiaries:

	2023	2022
Statements of Financial Position		
Trade and other receivables (e)	$ (13,208)	$ (8,550)
Property, plant and equipment (f)	559	150
Trade and other payables (g)	201	122
Loans and borrowings (e)	74,368	67,710
Provisions (h)	127	175

(e) Relates to short-term and long-term notes receivable to or payable from EPCOR.
(f) Relates to expenditures for information services projects.
(g) Relates to balances payable for administration of services and accrued interest on long-term notes payable to EPCOR.
(h) Relates to provisions for employee benefits.

(In thousands of Canadian dollars unless otherwise indicated)

20. Financial instruments

Classification

The classification of the Partnership's financial instruments at December 31, 2023 and 2022 are summarized as follows:

	Classification			
	Fair value through profit or loss	Fair value through other comprehensive income	Amortized cost	Fair value hierarchy
Measured at amortized cost				
Cash and cash equivalents	X			Level 1
Trade and other receivables			X	Level 3
Trade and other payables			X	Level 3
Loans and borrowings			X	Level 2
Customer deposits			X	Level 3

Fair value

The carrying amounts of cash, trade and other receivables, customer deposits and trade and other payables approximate their fair values due to the short-term nature of these financial instruments.

The carrying amount and fair value of the Partnership's remaining financial instrument are as follows:

	2023		2022	
	Carrying amount	Fair value	Carrying amount	Fair value
Loans and borrowings (note 12)	$ 74,368	$ 58,262	$ 67,710	$ 50,393

Fair value hierarchy

The financial instruments of the Partnership have been disclosed at fair value using a fair value hierarchy. A Level 1 valuation is determined by unadjusted quoted prices in active markets for identical assets or liabilities. A Level 2 valuation is based upon inputs other than quoted prices included in Level 1 that are observable for the instruments either directly or indirectly. A Level 3 valuation for the assets and liabilities are not based on observable market data.

Loans and borrowings

Short-term loans and borrowings are measured at amortized cost and their carrying value approximate their fair value due to the short-term nature of these financial instruments.

The fair value of the Partnership's long-term loans and borrowings is based on determining a current yield for the Partnership's debt at December 31, 2023 and 2022. This yield is based on an estimated credit spread for the Partnership over the yields of long-term Government of Canada bonds for Canadian dollar loans that have similar maturities to the Partnership's debt.

21. Financial risk management

Overview

The Partnership is exposed to a number of different financial risks arising from business activities and its use of financial instruments, including market risk, credit risk, and liquidity risk. The Partnership's overall risk management process is designed to identify, assess, measure, manage, mitigate and report on business risk, which includes financial risk. Enterprise risk management is overseen by the Board of Directors of EPCOR and senior management is responsible for fulfilling objectives, targets, and policies approved by the Board of Directors of EPCOR. EPCOR's Director of Audit and Risk Management provides the Board of Directors of EPCOR with an enterprise risk assessment on a quarterly basis. Risk management strategies, policies, and limits are designed to help ensure the risk exposures are managed within the EPCOR's business objectives and risk tolerance. The Partnership's financial risk management objective is to protect and minimize volatility in earnings and cash flow.

Financial risk management including interest rate risk, liquidity risk and the associated credit risk management is carried out by EPCOR's centralized Treasury function in accordance with applicable policies. The Audit Committee of the Board of Directors of EPCOR, in its oversight role, performs regular and ad-hoc reviews of risk management controls and procedures to help monitor compliance.

Market risk

Market risk is the risk of loss that results from changes in market factors such as energy prices and interest rates. The level of market risk to which the Partnership is exposed at any point in time varies depending on market conditions, expectations of future price or market rate movements and the composition of the Partnership's financial assets and liabilities held. EPCOR's financial exposure management policy is approved by the Board of Directors of EPCOR and the associated procedures and practices are designed to manage the interest rate risk throughout the Partnership.

Interest rate risk

The Partnership is exposed to interest rate risk from the possibility that changes in the interest rates will affect future cash flows or the fair values of its financial instruments. Interest rate risk associated with short-term loans and borrowings is immaterial due to their short-term maturity. At December 31, 2023 and 2022, all long-term loans and borrowings were fixed rate.

Credit risk

Credit risk is the possible financial loss associated with the inability of counterparties to satisfy their contractual obligations to the Partnership, including payment and performance. EPCOR's credit risk management policy is approved by the Board of Directors of EPCOR and the associated procedures and practices are designed to manage the credit risks associated with the various business activities throughout the group including the Partnership. Credit and counterparty risk management procedures and practices generally include assessment of individual counterparty creditworthiness and establishment of exposure limits prior to entering into a transaction with the counterparty. Exposures and concentrations are subsequently monitored and are regularly reported to senior management. Creditworthiness continues to be evaluated after transactions have been initiated, at a minimum, on an annual basis.

To manage and mitigate credit risk, the Partnership employs various credit mitigation practices such as master netting agreements, pre-payment arrangements from customers and other forms of credit enhancements including cash deposits, parent company guarantees, and bank letters of credit.

Maximum credit risk exposure

The Partnership's maximum credit exposure is represented by the carrying amount of the trade and other receivables balance of $4,491 (2022 – $4,440) (note 8). These carrying amounts do not take into account collateral held. At December 31, 2023, the Partnership held cash deposits of $386 (2022 – $373 cash deposits) as security for certain counterparty accounts receivable.

Credit quality and concentrations

The Partnership is exposed to credit risk on outstanding trade receivables associated with natural gas services to customers.

(In thousands of Canadian dollars unless otherwise indicated)

21. Financial risk management (continued)

The Partnership's trade receivables are unrated, unsecured and not of investment grade.

Rate-regulated customer credit risk

Credit risk exposure is generally limited to amounts due from residential and commercial customers for natural gas consumed but not yet paid for. The Partnership mitigates credit risk from counterparties by performing credit checks and on higher risk customers, by taking pre-payments or cash deposits.

Trade and other receivables and ECL allowance

Trade and other receivables consist primarily of amounts due from retail customers including residential and commercial customers. The Partnership mitigates these exposures by dealing with creditworthy counterparties and, when appropriate and contractually allowed, obtaining appropriate security from customers.

For retail customers, represented by a diversified customer base, credit losses are generally low and the Partnership provides an allowance for lifetime ECL.

The Partnership calculates the ECL allowance on accounts receivable using a provision matrix approach, which is based on the Partnership's historical credit loss experience and current economic conditions (including forward-looking information) for accounts receivables to estimate the lifetime ECL allowance. The provision matrix specifies fixed provision rates depending on the number of days that a trade receivable is due or past due. The total lifetime ECL allowance at December 31, 2023 is $221 (2022 – $100).

The gross amount of trade receivables and corresponding ECL is as follows:

December 31, 2023	Gross trade receivables	Expected credit loss allowance	Net trade receivables
Current [(a)]	$ 4,356	$ 43	$ 4,313
Outstanding 31 to 60 days	175	26	149
Outstanding 61 to 90 days	23	9	14
Outstanding more than 90 days	158	143	15
	$ 4,712	$ 221	$ 4,491

December 31, 2022	Gross trade receivables	Expected credit loss allowance	Net trade receivables
Current [(a)]	$ 4,407	$ 41	$ 4,366
Outstanding 31 to 60 days	78	13	65
Outstanding 61 to 90 days	10	5	5
Outstanding more than 90 days	45	41	4
	$ 4,540	$ 100	$ 4,440

(a) Current amounts represent trade and other receivables as well as accrued revenues outstanding up to 30 days. Amounts outstanding for more than 30 days are considered past due.

The change in the ECL allowance was as follows:

	2023	2022
Balance, beginning of year	$ 100	$ 49
Additional allowances created	121	69
Recovery of receivables	-	1
Receivables written off	-	(18)
Balance, end of year	$ 221	$ 100

(In thousands of Canadian dollars unless otherwise indicated)

21. Financial risk management (continued)

During the year, the Partnership recognized $121 (2022 – $69) ECL as expense in profit or loss relating to customer amounts that the Partnership determined may not be fully collectable. The lifetime ECL allowance is determined by considering the unique factors of different customer types. Write-offs are determined either by applying specific risk factors to customer groups' aged balances in trade and other receivables or by reviewing material accounts on a case-by-case basis. Reductions in trade and other receivables and the related ECL allowance is recorded when the Partnership has determined that recovery is not possible.

Liquidity risk

Liquidity risk is the risk that the Partnership will not be able to meet its financial obligations as they become due. The Partnership's liquidity is managed centrally by EPCOR's Treasury function. EPCOR manages liquidity risk through regular monitoring of cash and currency requirements by preparing short-term and long-term cash flow forecasts and by matching the maturity profiles of financial assets and liabilities to identify financing requirements. The financing requirements of the Partnership are addressed through operating cash flows, and if necessary, intercompany financing from EPCOR.

The undiscounted cash flow requirements and contractual maturities of the Partnership's financial liabilities, including interest payments, are as follows:

At December 31, 2023:

	2024	2025	2026	2027	2028	2029 and thereafter	Total contractual cash flows
Trade and other payables[1]	$ 8,872	$ -	$ -	$ -	$ -	$ -	$ 8,872
Customer Deposits	386	-	-	-	-	-	386
Loans and borrowings	13,208	-	-	-	-	61,160	74,368
Interest payments on loans and borrowings	1,986	2,054	2,054	2,054	2,054	47,636	57,838
Lease liabilities	44	47	49	52	55	43	290
	$ 24,496	$ 2,101	$ 2,103	$ 2,106	$ 2,109	$ 108,839	$ 141,754

(1) Excluding accrued interest on loans and borrowings of $83 (2022 – $75).

The Partnership's undiscounted cash flow requirements and contractual maturities in the next twelve months of $24,496 (2022 – $20,834) will be funded from operating cash flows and additional loans and borrowings.

(In thousands of Canadian dollars unless otherwise indicated)

22. Capital management

The Partnership's primary objectives when managing capital is to safeguard the Partnership's ability to continue as a going concern and pay cash distributions to its unit holders. The Partnership manages its capital structure in a manner consistent with the risk characteristics of the underlying assets and in accordance with OEB regulatory decisions.

The Partnership manages capital through regular monitoring of cash requirements by preparing short-term and long-term cash flow forecasts and reviewing monthly financial results. The Partnership matches the maturity profiles of financial assets and liabilities to identify financing requirements to help ensure an adequate amount of liquidity.

The Partnership considers its capital structure to consist of loans and borrowings (including current portion) net of cash and unit holder's equity. The following table represents the Partnership's total capital:

	2023	2022
Loans and borrowings (including current portion) (note 12)	$ 74,368	$ 67,3710
Cash	-	(7)
Net debt	74,368	67,703
Total equity	47,538	45,507
Total capital	$ 121,906	$ 113,210

To manage or adjust its capital structure, the Partnership can issue new debt, repay existing debt or issue or redeem common units.

23. Commitments and contingencies

The following are the Partnership's commitments and contingencies not otherwise disclosed in these financial statements as at December 31, 2023:

(a) Commitments for the minimum cost of the monthly demand charge from Enbridge regardless of the total volume of gas delivered into the distribution system estimated at $1,382 (2022 – $1,407) annually.

(b) Commitments for the purchase of general administrative and operation services from EPCOR and its subsidiaries are estimated at $2,435 (2022 – $2,343) annually. These estimates are subject to change based on actual activity levels.

(c) Commitments for the purchase of design and construction services from Aecon Construction Group Inc. are estimated at $301 (2022 – $895) remaining on the contract to construct the Southern Bruce gas distribution infrastructure. The Partnership will require financing from the parent company to settle these commitments.

(In thousands of Canadian dollars unless otherwise indicated)

24. Divisional information

The Partnership operates two divisions that are geographically separated in Southwestern Ontario: Aylmer and Southern Bruce. Divisional information for the reporting period is as follows:

	Aylmer Operations	Southern Bruce Operations	Brockton Operations[1]	2023 Total
Revenue	$ 18,833	$ 9,383	$ -	$ 28,216
Operating expenses:				
Energy purchases	10,208	2,854	-	13,062
Staff costs and employee benefits expenses	1,353	643	(2)	1,994
Depreciation and amortization (note 6)	1,274	3,526	927	5,727
Other raw materials and operating charges	2,332	1,210	-	3,542
Franchise fees and property taxes	660	406	-	1,066
Other administrative expenses	1,943	1,864	-	3,807
	17,770	10,503	925	29,198
Operating income (loss)	1,063	(1,120)	(925)	(982)
Finance expenses (note 7)	(557)	(2,430)	-	(2,987)
Comprehensive income (loss) for the year - all attributable to the Partners	$ 506	$ (3,550)	$ (925)	$ (3,969)

	Aylmer Operations	Southern Bruce Operations	Brockton Operations	2022 Total
Revenue	$ 17,741	$ 6,452	-	$ 24,193
Operating expenses:				
Energy purchases	10,175	1,753	-	11,928
Staff costs and employee benefits expenses	1,320	374	-	1,694
Depreciation and amortization (note 6)	1,146	2,920	-	4,066
Other raw materials and operating charges	2,448	1,110	-	3,558
Franchise fees and property taxes	615	342	-	957
Other administrative expenses	1,918	1,501	-	3,419
	17,622	8,000	-	25,622
Operating income (loss)	119	(1,548)	-	(1,429)
Finance expenses (note 7)	(439)	(1,655)	-	(2,094)
Comprehensive income (loss) for the year - all attributable to the Partners	$ (320)	$ (3,203)	-	$ (3,522)

1 An application to expand natural gas distribution in several municipalities was withdrawn due to procedural delays that would impact the ability to construct in time for the 2024 construction season. Capital costs incurred to date were written off to income.

ENGLP – Financial Statement Reconciliation

2021 Reconciliation ($000's)

Income Statement

	Audited	Adjustments	Regulatory
Energy Sales	5,681	46	5,727
Commercial Services	7,580	(305)	7,275
Revenues	13,261	(259)	13,002
Energy Purchases and System Access Fees	(5,795)	27	(5,768)
Other Raw Materials and Operating Charges	(2,062)	115	(1,947)
Staff Costs and Employee Benefits Expense	(1,248)	6	(1,242)
Depreciation and Amortization Expense	(1,092)	173	(919)
Other Administrative Expenses	(1,530)		(1,530)
Franchise Fees & Property Taxes	(601)	(111)	(712)
Expenses	(12,328)	210	(12,118)
Operating income	933	(49)	884
Net Finance Expense	(402)	5	(397)
(Loss)/income before tax	531	(44)	487
Current Income Tax	-	-	-
Deferred Income Tax	-	-	-
(Loss)/profit for the year	531	(44)	487

Balance Sheet

	Audited	Adjustments	Regulatory
ASSETS			
Current assets			
Cash and cash equivalents	5	-	5
Trade and other receivables	2,322	387	2,709
Prepaid expenses	21	-	21
Inventories	179	-	179
Total current assets	2,527	387	2,914
Non-current assets			
Intangible assets	1,053	(457)	596
Property, plant and equipment	23,831	(5,636)	18,195
Goodwill	1,808	(1,808)	-
Total non-current assets	26,692	(7,901)	18,791
TOTAL ASSETS	29,219	(7,514)	21,705
LIABILITIES AND EQUITY			
Trade and other payables	2,058	(302)	1,756
Loans and borrowings	2	1	3
Provision	93	-	93
Other current liabilities/Customer Deposits	306	(19)	287
Total current liabilities	2,459	(320)	2,139
Loans and borrowings	11,160	-	11,160
Deferred revenues	827	12	839
Other non-current liabilities	-		-
Total non-current liabilities	11,987	12	11,999
Total liabilities	14,446	(308)	14,138
Share capital	13,360	(7,749)	5,611
Retained earnings	1,413	543	1,956
Total equity	14,773	(7,206)	7,567
TOTAL LIABILITIES AND EQUITY	29,219	(7,514)	21,705

2022 Reconciliation ($000's)

Income Statement

Income Statement	Audited	Adjustments	Regulatory
Energy Sales	9,126	51	9,177
Commercial Services	8,615	(400)	8,215
Revenues	17,741	(349)	17,392
Energy Purchases and System Access Fees	(10,175)	997	(9,178)
Other Raw Materials and Operating Charges	(2,402)	110	(2,292)
Staff Costs and Employee Benefits Expense	(1,320)	-	(1,320)
Depreciation and Amortization Expense	(1,146)	199	(947)
Other Administrative Expenses	(1,921)	10	(1,911)
Franchise Fees & Property Taxes	(615)	(111)	(726)
Expenses	(17,579)	1,205	(16,374)
Operating income	162	856	1,018
Net Finance Expense	(438)	(13)	(451)
(Loss)/income before tax	(276)	843	567
Current Income Tax	-	-	-
Deferred Income Tax	-	-	-
(Loss)/profit for the year	(276)	843	567

Balance Sheet

Balance Sheet	Audited	Adjustments	Regulatory
ASSETS			
Current assets			
Cash and cash equivalents	7	-	7
Trade and other receivables	3,264	408	3,672
Prepaid expenses	22	-	22
Inventories	277	(43)	234
Total current assets	3,570	365	3,935
Non-current assets			
Intangible assets	1,004	(426)	578
Property, plant and equipment	25,111	(5,481)	19,630
Goodwill	1,808	(1,808)	-
Total non-current assets	27,923	(7,715)	20,208
TOTAL ASSETS	31,493	(7,350)	24,143
LIABILITIES AND EQUITY			
Trade and other payables	3,478	(679)	2,799
Loans and borrowings	1,031	(7)	1,024
Provision	128	-	128
Other current liabilities/Customer Deposits	288	(22)	266
Total current liabilities	4,925	(708)	4,217
Loans and borrowings	11,160	-	11,160
Deferred revenues	911	14	925
Other non-current liabilities	-		-
Total non-current liabilities	12,071	14	12,085
Total liabilities	16,996	(694)	16,302
Share capital	13,360	(7,749)	5,611
Retained earnings	1,137	1,093	2,230
Total equity	14,497	(6,656)	7,841
TOTAL LIABILITIES AND EQUITY	31,493	(7,350)	24,143

2023 Reconciliation ($000's)

Income Statement

Income Statement	Audited	Adjustments	Regulatory
Energy Sales	10,462	23	10,485
Commercial Services	8,371	58	8,429
Revenues	18,833	81	18,914
Energy Purchases and System Access Fees	(10,208)	(277)	(10,485)
Other Raw Materials and Operating Charges	(2,375)	233	(2,142)
Staff Costs and Employee Benefits Expense	(1,353)	-	(1,353)
Depreciation and Amortization Expense	(1,274)	225	(1,049)
Other Administrative Expenses	(1,943)	(3)	(1,946)
Franchise Fees & Property Taxes	(660)	(32)	(692)
Expenses	(17,813)	146	(17,667)
Operating income	1,020	227	1,247
Net Finance Expense	(557)	57	(500)
(Loss)/income before tax	463	284	747
Current Income Tax	-	-	-
Deferred Income Tax	-	-	-
(Loss)/profit for the year	463	284	747

Balance Sheet

Balance Sheet	Audited	Adjustments	Regulatory
ASSETS			
Current assets			
Cash and cash equivalents	-	-	-
Trade and other receivables	3,327	2,020	5,347
Prepaid expenses	31	-	31
Inventories	756	-	756
Total current assets	4,114	2,020	6,134
Non-current assets			
Intangible assets	1,002	(394)	608
Property, plant and equipment	26,276	(5,352)	20,924
Goodwill	1,808	(1,808)	-
Total non-current assets	29,086	(7,554)	21,532
TOTAL ASSETS	33,200	(5,534)	27,666
LIABILITIES AND EQUITY			
Trade and other payables	2,594	1,781	4,375
Loans and borrowings	1,062	(66)	996
Provision	111	-	111
Other current liabilities/Customer Deposits	284	(26)	258
Total current liabilities	4,051	1,689	5,740
Loans and borrowings	12,160	-	12,160
Deferred revenues	1,029	18	1,047
Other non-current liabilities	-	-	-
Total non-current liabilities	13,189	18	13,207
Total liabilities	17,240	1,707	18,947
Share capital	14,360	(7,749)	6,611
Retained earnings	1,600	508	2,108
Total equity	15,960	(7,241)	8,719
TOTAL LIABILITIES AND EQUITY	33,200	(5,534)	27,666

ENGLP – Pro Forma Financial Statements 2024B and 2025T

2024 Bridge Year Forecasted Financial Statements – Aylmer

($000's)

Energy Sales	9,759
Commercial Services	7,557
Revenues	17,316
Energy Purchases and System Access Fees	(9,759)
Other Raw Materials and Operating Charges	(387)
Staff Costs and Employee Benefits Expense	(1,285)
Depreciation and Amortization Expense	(1,186)
Other Administrative Expenses	(2,449)
Franchise Fees & Property Taxes	(675)
Expenses	(15,741)
Operating income	1,575
Net Finance Expense	(628)
(Loss)/income before tax	947
Current Income Tax	(56)
Deferred Income Tax	-
(Loss)/profit for the year	891

Balance Sheet

ASSETS	
Current assets	
Cash and cash equivalents	-
Trade and other receivables	5,267
Prepaid expenses	33
Inventories	756
Total current assets	6,056
Non-current assets	
Intangible assets	518
Property, plant and equipment	24,755
Goodwill	-
Total non-current assets	25,273
TOTAL ASSETS	31,329
LIABILITIES AND EQUITY	
Trade and other payables	3,008
Loans and borrowings	2,089
Provision	112
Other current liabilities/Customer Deposits	258
Total current liabilities	5,467
Loans and borrowings	14,160
Deferred revenues	1,092
Total non-current liabilities	15,252
Total liabilities	20,719
Share capital	7,611
Retained earnings	2,999
Total equity	10,610
TOTAL LIABILITIES AND EQUITY	31,329

2025 Test Year Forecasted Financial Statements – Aylmer

($000's)

Energy Sales	9,992
Commercial Services	8,077
Revenues	18,069
Energy Purchases and System Access Fees	(9,992)
Other Raw Materials and Operating Charges	(526)
Staff Costs and Employee Benefits Expense	(1,474)
Depreciation and Amortization Expense	(1,349)
Other Administrative Expenses	(2,308)
Franchise Fees & Property Taxes	(706)
Expenses	(16,355)
Operating income	1,714
Net Finance Expense	(658)
(Loss)/income before tax	1,056
Current Income Tax	(75)
Deferred Income Tax	-
(Loss)/profit for the year	981

ASSETS	
Current assets	
Cash and cash equivalents	-
Trade and other receivables	5,424
Prepaid expenses	33
Inventories	756
Total current assets	6,213
Non-current assets	
Intangible assets	865
Property, plant and equipment	27,194
Goodwill	-
Total non-current assets	28,059
TOTAL ASSETS	34,272
LIABILITIES AND EQUITY	
Trade and other payables	3,055
Loans and borrowings	2,961
Provision	112
Other current liabilities/Customer Deposits	258
Total current liabilities	6,386
Loans and borrowings	15,160
Deferred revenues	1,135
Total non-current liabilities	16,295
Total liabilities	22,681
Share capital	7,611
Retained earnings	3,980
Total equity	11,591
TOTAL LIABILITIES AND EQUITY	34,272