EPCOR Natural Gas Limited Partnership

Cost of Service Application
EB-2024-0130
July 18, 2024

Exhibit 2 – Rate Base and Utility System Plan

PROVIDING MORE EPCOR

Contents

2.1 Rate Base Overview

The purpose of this section is to provide ENGLP's projected rate base for its Aylmer operations and explanations for deviations.

The mid-year rate base in 2025 Test Year is projected to be $26.63M. The projected rate base is calculated as the utility's average in-service gross fixed assets and offset by both the accumulated depreciation and net value of contributions received. ENGLP uses the half-year rule for calculating the average in-service fixed assets for the test year. ENGLP has also included an allowance for working capital application in this filing which has been added in the test year (refer to section 2.3.)

Table 2.1-1 below summarizes the historical, 2024 Bridge and 2025 Test Year rate base for ENGLP. The rate base is broken down by gross plant, accumulated depreciation and working capital. Variance drivers are included further in this Exhibit.

Table 2.1-1
2020-2025 Rate Base ($000's)

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

2.2 Gross Assets – Property, Plant and Equipment and Accumulated Depreciation

2.2.1 Breakdown by Function

ENGLP has categorized its gross assets into 4 primary categories or functions and has shown the breakdown in Table 2.2.1-1 below:

- Distribution Plant: Includes assets such as meters, pipelines and regulators;
- General Plant: Includes assets such as buildings, vehicles and computer hardware;
- Intangible Plant: Includes the franchise assets; and,
- Contributions & Grants: Includes contributions made towards capital.

Table 2.2.1-1

Gross Plant by Function ($000's)

Description	2020 OEB Approved	2020 A	2021 A	2022 A	2023 A	2024 Bridge Year	2025 Test Year
Distribution Plant	22,662	24,366	26,075	27,473	30,224	34,869	38,398
Distribution (IGPC)	7,142	6,573	6,573	6,821	6,821	7,121	7,421
General Plant	3,446	3,527	3,783	4,143	4,407	4,579	4,886
Intangible Plant	768	770	770	770	843	843	843
Subtotal	**34,018**	**35,237**	**37,201**	**39,208**	**42,295**	**47,412**	**51,548**
Contributions	(199)	(287)	(510)	(589)	(763)	(835)	(907)
Contributions (IGPC)	(590)	(376)	(376)	(376)	(376)	(376)	(376)
Grand Total	**33,230**	**34,574**	**36,315**	**38,243**	**41,156**	**46,201**	**50,265**

The tables below expands Table 2.2.1-1 by relevant USoA account.

Table 2.2.1-2
Gross Plant by Uniform System of Account (USoA) ($000's)

	Description	A USoA	B 2020 OEB Approved	C 2020 A	D 2021 A	E 2022 A	F 2023 A	G 2024 Bridge Year	H 2025 Test Year
1	**Distribution Plant**								
2	Meters - Commercial	478	1,207	1,708	1,838	1,920	1,926	2,086	2,243
3	Meters - Residential	478	1,173	1,763	1,823	2,165	2,623	3,448	4,269
4	Meters - IGPC	478	14	14	14	14	14	14	14
5	Regulators	474	144	591	666	739	808	1,113	1,369
6	Measuring & Regulating Equip	477	2,102	1,705	1,744	1,833	2,099	2,441	2,539
7	Measuring & Regulating Equip (IGPC)	477	-	576	576	576	576	576	576
8	Mains - Metallic (IGPC)	475	7,128	5,983	5,983	6,231	6,231	6,531	6,831
9	Mains - Plastic	475	13,732	13,767	14,600	14,940	16,153	18,334	19,715
10	Services - Plastic	473	4,304	4,832	5,402	5,876	6,615	7,446	8,263
11	**Subtotal**		**29,804**	**30,940**	**32,648**	**34,295**	**37,045**	**41,990**	**45,819**
12	**General Plant**								
13	Land	480	123	72	83	83	83	83	83
14	Structures & Improvements	482	762	700	700	700	783	783	906
15	Furnishing / Office Equipment	483	113	150	201	201	201	201	201
16	Computer Equipment	490	258	440	514	567	581	609	666
17	Software - Acquired	491	607	654	655	711	748	755	765
18	Tools and Work Equipment	486	778	755	771	841	894	918	941
19	Communication Equipment	488	231	246	311	311	313	326	343
20	Vehicles - Transportation Equip	484	576	477	516	697	771	873	949
21	Vehicle - Heavy Work Equip	485	-	33	33	33	33	33	33
22	**Subtotal**		**3,446**	**3,527**	**3,783**	**4,143**	**4,407**	**4,579**	**4,886**
23	**Intangible Plant**								
24	Franchises	401	768	770	770	770	843	843	843
25	**Subtotal**		**768**	**770**	**770**	**770**	**843**	**843**	**843**
26	**Contributions**	499	**(199)**	**(287)**	**(510)**	**(589)**	**(763)**	**(835)**	**(907)**
27	**Contributions (IGPC)**	499	**(590)**	**(376)**	**(376)**	**(376)**	**(376)**	**(376)**	**(376)**
28	**Grand Total**		**33,230**	**34,574**	**36,315**	**38,243**	**41,156**	**46,201**	**50,265**

ENGLP confirms the depreciation expense for 2020 to 2025 in row 8 of Table 2.1-1, above, reconciles to the depreciation expense reported in Table 4.4-3 of Exhibit 4 (Test Year Depreciation Expense by Asset Group), as well as to the depreciation reported in the continuity schedules for each asset group, provided in Appendix 2C – (Exhibit 2, Tab 1 Schedule 2) and in Excel Appendix 2C_Fixed Asset Continuity.

Table 2.2.1-3
Depreciation Expense by Account (USoA) ($000's)

	Description	A USoA	B 2020 OEB Approved	C 2020 A	D 2021 A	E 2022 A	F 2023 A	G 2024 Bridge Year	H 2025 Test Year
1	**Distribution Plant**								
2	Meters - Commercial	478	$84	$64	$69	$74	$77	$51	$57
3	Meters - Residential	478	$125	$283	$142	$154	$176	$105	$185
4	Meters - IGPC	478	$8	$8	$0	$0	$0	$0	$0
5	Regulators	474	$12	$12	$15	$18	$21	$27	$40
6	Measuring & Regulating Equip	477	$48	$28	$33	$35	$41	$50	$55
7	Measuring & Regulating Equip (IGPC)	477	$0	$21	$21	$21	$21	$21	$21
8	Mains - Metallic (IGPC)	475	$87	$70	$80	$81	$79	$155	$154
9	Mains - Plastic	475	$259	$253	$272	$284	$301	$420	$442
10	Services - Plastic	473	$42	$48	$65	$75	$90	$172	$185
11	**Subtotal**		$665	$786	$697	$743	$807	$1,002	$1,140
12	**General Plant**								
13	Land	480		$0	$0	$0	$0	$2	$2
14	Structures & Improvements	482	$15	$11	$11	$11	$12	$19	$19
15	Furnishing / Office Equipment	483	$2	$3	$9	$8	$8	$5	$5
16	Computer Equipment	490	$57	$58	$50	$33	$40	$18	$28
17	Software - Acquired	491	$50	$29	$33	$36	$41	$44	$44
18	Tools and Work Equipment	486	$18	$17	$18	$20	$24	$23	$23
19	Communication Equipment	488	$5	$5	$13	$11	$11	$11	$12
20	Vehicles - Transportation Equip	484	$51	$48	$53	$62	$75	$27	$41
21	Vehicle - Heavy Work Equip	485		$2	$2	$2	$2	$1	$1
22	**Subtotal**		$197	$173	$190	$183	$213	$149	$175
23	**Intangible Plant**								
24	Franchise & Consents	401	$33	$31	$32	$32	$33	$35	$35
25	**Subtotal**		$33	$31	$32	$32	$33	$35	$35
26	**Contributions**	499	-$5	-$6	-$10	-$13	-$16	-$18	-$20
27	**Contributions (IGPC)**	499	-$14	-$4	-$8	-$8	-$8	-$9	-$9
28	**Grand Total**		**$877**	**$981**	**$901**	**$936**	**$1,029**	**$1,159**	**$1,321**

2.2.2 Historical Capital Expenditures

ENGLP has established a threshold of $0.05 million ($50,000) per asset group for variances requiring explanations, as per the Board's requirements.

Table 2.2.2-1
Capital Additions by Account (USoA)
Net of Contributions
($000's)

	Description	A USoA	B 2020 Decision	C 2025 Test Year	C Difference (C-B)
1	**Distribution Plant**				
2	Meters - Commercial	478	262.3	157.0	(105.3)
3	Meters - Residential	478	125.7	820.9	695.2
4	Regulators	474	73.0	255.7	182.7
5	Measuring & Regulating Equip	477	75.0	97.9	22.9
6	Mains - Metallic (IGPC)	475	-	300.0	300.0
7	Mains - Plastic	475	574.0	1,356.4	782.4
8	Services - Plastic	473	100.0	768.9	668.9
9	**Subtotal**		**1,210.0**	**3,756.8**	**2,546.8**
10	**General Plant**				
11	Land	480	-	-	-
12	Structures & Improvements	482	31.0	123.5	92.5
13	Furnishing / Office Equipment	483	-	-	-
14	Computer Equipment	490	10.0	57.5	47.5
15	Software - Acquired	491	26.0	10.0	(16.0)
16	Tools and Work Equipment	486	16.0	23.0	7.0
17	Communication Equipment	488	-	17.5	17.5
18	Vehicles - Transportation Equip	484	47.0	75.5	28.5
19	**Subtotal**		**130.0**	**307.1**	**177.1**
20	**Intangible Plant**				
21	Franchises	401	-	-	-
22	**Subtotal**		**-**	**-**	**-**
23	**Grand Total**		**1,340.0**	**4,063.9**	**2,723.9**

Capital Variances 2020-2024

ENGLP's capital spend has varied from its USP filed in 2019 as per the table below (2.2.2-1). This deviation was less driven by the scope of work being completed, but rather an increase in the standards to which work is completed. The effect of this required transition to industry standard is an increase in the capital cost of construction. The following sections explain the reason for this transition, how it was achieved and the impact.

Other factors driving the variances in historical data include the unplanned connection of several large customers, which were not contemplated in the previous USP, along with a meter replacement program based on the expiration of customer meters in accordance with Measurement Canada Standards. The variance associated to the meter replacement program is a timing variance to the previous USP. The majority of meters have reached their end of life in 2023-25 whereas the previous USP had the renewal spend being spread out between 2020-24.

Table 2.2.2-2

2020-2024 Variance vs. Historical USP($000's)

	2020	2021	2022	2023	2024
2019 USP	$1,340	$1,457	$1,239	$1,261	$1,288
Actual	$2,333	$1,999	$2,418	$2,366	$5,045
Variance	$993	$542	$1,179	$1,106	$3,757

The 2020-2024 USP budgeted an average cost per service of $653 based on the assumption that ENGLP's internal construction crew was performing the service construction and used the historical averages accounted for on record from the previous owner. The cost of a service is influenced by many factors, such as the length of service, the size of service, the time of year the work is completed, whether the work is in a built-up area (requiring civil works or drilling) or a new build area (open trench), and who performs the work. These variables all contribute to significantly different costs as seen in Table 2.2.2-3.

Table 2.2.2-3

2025-2029 Cost Per Service	2020-2024 USP	2020-2023 A	2025-2029 USP
Services	$ 164,000	$ 552,212	$ 821,308
Connections	251	228	175
Cost per Service	$ 653	$ 2,426	$ 4,693

ENGLP has been reviewing and strengthening construction standards since EPCOR's acquisition of NRG and during the Southern Bruce construction project. There have been some learnings from the construction of the Southern Bruce project that have influenced ENGLP's standards. In particular, ENGLP experienced multiple butt fuse failures on plastic mains in Southern Bruce, and an emergency leak on the steel IGPC pipeline. The investigation of these failures resulted in several corrective actions being implemented across ENGLP's gas pipeline contruction program and an increase to standards of construction[1]. ENGLP does not have the internal resources to construct to these upgraded standards, and has had to contract out this new construction. To ensure these standards can be met and to ensure competitive costs, ENGLP conducted a competitive procurement process in 2021-22.

During the years 2020-2021, ENGLP had already contracted out much of its construction work because it did not possess the required equipment to complete the mains and services (e.g. road bore drills). This work was completed by contractors that had previously worked with NRG. Following the competitive bid process in 2021, via a negotiated request for proposal ("**NRFP**"), ENGLP partnered with a new contractor. While this has led to increased service installation costs, ENGLP believes that the outcome of this transparent and robust tender process results in a more consistent and safe connection process, which is beneficial to customers. The contractor chosen was the most competitive among the compliant bids (note the contractors that were used in the years 2020-21 did not submit a bid or had a non-compliant bid). Accordingly, the cost per service

[1] ENGLP-SOP-OPS-01-Specification for Installing Pipe by Open Cut Directional Drill; ENGLP-SOP-OPS-01-Pressure Testing; ENGLP-SOP-OPS-01-Backfill Specification; ENGLP-SOP-OPS-03-Polytheylene Fusion Procedure; ENGLP-SOP-OPS-01- Handling & Storage of Plastic Pipe & Fitting; ENGLP-SOP-OPS-01-Safe Blowdown of a Pipeline & Purging Gas or Air; ENGLP-SOP-MCE-00-In Service Sleeve Maintenance Welding

is on average lower during the years 2020-2023 vs. the 2025-29 USP as seen in Table 2.2.2-3 because there were a mixture of contractors used during this time (2020-21 & 2022-2023). It is relevant to point out that the 2025-2029 USP cost per service of $4,693 is comparable to that of Enbridge Distribution of $4,412.[2]

The contractor chosen moving forward brought the following capabilities that ENGLP did not have:

- Emergency response and repair capability on steel pipeline. ENGLP has 30 kms of steel pipeline feeding an industrial customer in Aylmer
- Construction of plastic mains and services in Aylmer from 6” to ½”; and,
- Engineering and design for Natural Gas Construction.

In addition, the investigation around the 2021 butt fuse failure in Southern Bruce resulted in ENGLP implementing a more robust internal quality assurance/quality control program. This program will require increased owner inspections to ensure contractor compliance to safety codes and practices in ENGLP’s juristictions. An shared ENGLP inspector role was required in order implement this program. The inspector will collect and analyze information on ENGLP installed assets constructed by its contractor partners. ENGLP increased the frequency of inspection around fusions and pressure testing of its assets. The inspector ensures that ENGLP’s contractors have implemented ENGLP’s fusion procedure to industry standards, which is a necessary function of contractor management and key to safe and reliablie contruction.

The tables below provide annual variances including:

- 2020T vs. 2020A
- 2020A vs. 2021A
- 2021A vs. 2022A
- 2022A vs. 2023A
- 2023A vs. 2024B
- 2024B vs. 2025T

[2] EB-2022-0200 Decision and Order, December 21, 2023, Page 25

Table 2.2.2-4
2020 Prior Test (EB-2018-0336) vs. 2020 Actual Capital Additions
Net of Contributions
($000's)

		A	B	C	D
	Description	**USoA**	**2020 Decision**	**2020 A**	**Difference (C-B)**
1	**Distribution Plant**				
2	Meters - Commercial	478	262.3	82.2	(180.1)
3	Meters - Residential	478	125.7	180.9	55.2
4	Regulators	474	73.0	27.2	(45.8)
5	Measuring & Regulating Equip	477	75.0	656.1	581.1
6	Mains - Metallic (IGPC)	475	-	(41.2)	(41.2)
7	Mains - Plastic	475	574.0	1,214.8	640.8
8	Services - Plastic	473	100.0	470.6	370.6
9	**Subtotal**		**1,210.0**	**2,590.8**	**1,380.8**
10	**General Plant**				
11	Land	480	-	-	-
12	Structures & Improvements	482	31.0	-	(31.0)
13	Furnishing / Office Equipment	483	-	37.8	37.8
14	Computer Equipment	490	10.0	29.7	19.7
15	Software - Acquired	491	26.0	91.4	65.4
16	Tools and Work Equipment	486	16.0	-	(16.0)
17	Communication Equipment	488	-	47.4	47.4
18	Vehicles - Transportation Equip	484	47.0	63.9	16.9
19	**Subtotal**		**130.0**	**270.1**	**140.1**
20	**Intangible Plant**				
21	Franchises	401	-	2.5	2.5
22	**Subtotal**		**-**	**2.5**	**2.5**
23	**Grand Total**		**1,340.0**	**2,863.4**	**1,523.4**

Account 478 – Meters

The $180K reduction compared to the previous test year for commercial meters is due to:

- A reduced number of commercial customers being connected and serviced compared to forecast.

The $55K increase compared to the previous test year for residential meters is due to:

- An increased number of residential services connected compared to forecast.

Account 477 – Measuring and Regulating Equipment

The increase compared to the previous test year is due to:

- The completion of the Lakeview station in 2020 and increased cost associated with installing 1,300 meters of 6inch PE pipe instead of 4inch PE coming out of the station in order to meet future peak demand volume requirements ($114K).
- The update of a previously existing obsolete SCADA system with a more reliable, modern platform. This investment was included in the EB-2018-0336 USP with $238K in 2019 and $128K in 2020. The project was initiated in 2019, but was completed in 2020 for a cost of $391K.

Account 475 – Mains

The $641K increase compared to the previous test year is due to:

- An increase in the cost of construction of mains installed to support the new connection growth compared to forecast. In 2020, 23 new gas mains (or 17,558m of mains) were installed.

Account 473 – Plastic Service Lines

The $371K increase compared to the previous test year is due to:

- The added cost to serve the Village of Salford (EB-2019-0232).
- As stated further at the beginning of this section, the costs per service increased from the cost of service filing because ENGLP had to make use of contractors. These contractors were required because ENGLP did not have the equipment necessary to do road bore drilling.

Account 491 – Computer Software

The $65K increase compared to the previous test year is due to:

- The Utility Management Software (UMS) web portal used for customer sign up and billing -$38K
- The ESRI GIS software used to replace Autocad, the historic system of record - $32K. The GIS permits real time updates of system additions making it safer for locators when finding our assets.

Table 2.2.2-2
2020 Actual vs. 2021 Actual Capital Additions
Net of Contributions
($000's)

	Description	A USoA	B 2020 A	C 2021 A	D Difference (C-B)
1	**Distribution Plant**				
2	Meters - Commercial	478	82.2	130.4	48.2
3	Meters - Residential	478	180.9	60.7	(120.2)
4	Regulators	474	27.2	75.2	48.0
5	Measuring & Regulating Equip	477	656.1	38.7	(617.4)
6	Mains - Metallic (IGPC)	475	(41.2)	-	41.2
7	Mains - Plastic	475	1,214.8	697.2	(517.6)
8	Services - Plastic	473	470.6	482.4	11.7
9	**Subtotal**		**2,590.8**	**1,484.7**	**(1,106.1)**
10	**General Plant**				
11	Land	480	-	11.0	11.0
12	Structures & Improvements	482	-	-	-
13	Furnishing / Office Equipment	483	37.8	50.4	12.6
14	Computer Equipment	490	29.7	74.3	44.6
15	Software - Acquired	491	91.4	1.0	(90.4)
16	Tools and Work Equipment	486	-	15.6	15.6
17	Communication Equipment	488	47.4	65.1	17.7
18	Vehicles - Transportation Equip	484	63.9	38.6	(25.3)
19	**Subtotal**		**270.1**	**255.9**	**(14.2)**
20	**Intangible Plant**				
21	Franchises	401	2.5	-	(2.5)
22	**Subtotal**		**2.5**	**-**	**(2.5)**
23	**Grand Total**		**2,863.4**	**1,740.6**	**(1,122.8)**

Account 478 – Meters

The $48K increase compared to 2020A for commercial meters is due to:

- An increase in commercial customer connections.

The $120K decrease compared to 2020A for residential meters is due to:

- A reduction in residential services connections from 299 to 231

Account 474 – Regulators and Account 477 – Measuring and Regulating Equipment

The $569K decrease compared to 2020A is due to:

- The decrease in account 477 of $617.4K as a result of completing the SCADA upgrade project in 2020 and the Lakeview regulating station in early 2020.

Account 475 – Mains

The $518K decrease compared to 2020A is due to:

- A reduction in the ccompletion of main extensions (14 mains, 13,682m) in 2021 vs. 23 main extensions (17,558m) in 2020.

Account 491 – Computer Software

The $90K decrease compared to 2020A is due to:

- There being no required updates to the UMS web portal and GIS software, which was purchased in 2020.

Table 2.2.2-3
2021 Actual vs. 2022 Actual Capital Additions
Net of Contributions
($000's)

	Description	A USoA	B 2021 A	C 2022 A	D Difference (C-B)
1	**Distribution Plant**				
2	Meters - Commercial	478	130.4	82.1	(48.3)
3	Meters - Residential	478	60.7	341.7	280.9
4	Regulators	474	75.2	72.8	(2.4)
5	Measuring & Regulating Equip	477	38.7	88.9	50.2
6	Mains - Metallic (IGPC)	475	-	248.1	248.1
7	Mains - Plastic	475	697.2	283.6	(413.6)
8	Services - Plastic	473	482.4	450.2	(32.1)
9	**Subtotal**		**1,484.7**	**1,567.5**	**82.9**
10	**General Plant**				
11	Land	480	11.0	-	(11.0)
12	Structures & Improvements	482	-	-	-
13	Furnishing / Office Equipment	483	50.4	-	(50.4)
14	Computer Equipment	490	74.3	53.4	(20.9)
15	Software - Acquired	491	1.0	55.8	54.8
16	Tools and Work Equipment	486	15.6	70.4	54.8
17	Communication Equipment	488	65.1	-	(65.1)
18	Vehicles - Transportation Equip	484	38.6	180.9	142.3
19	**Subtotal**		**255.9**	**360.4**	**104.5**
20	**Intangible Plant**				
21	Franchises	401	-	-	-
22	**Subtotal**		**-**	**-**	**-**
23	**Grand Total**		**1,740.6**	**1,927.9**	**187.3**

Account 478 – Meters

The $48K decrease compared to 2021A for commercial meters is due to:

- Several commercial meters did not require any changes

The $281K increase compared to 2021A for residential meters is due to:

- Meters being purchased in 2022 to ensure inventory was on hand to replace in 2023. Meter life begins as soon as it is put on the shelf.

Account 484 – Vehicles – Transportation Equipment

The $142K increase compared to 2021A is due to:

- The purchase of three vehicles for operations – two pickup trucks to replace vans used by gas technicians and a vehicle for the General Manager. The vans were replaced for safety reasons.

Table 2.2.2-4
2022 Actual vs. 2023 Actual Capital Additions
Net of Contributions
($000's)

		A	B	C	C
	Description	**USoA**	**2022 A**	**2023 A**	**Difference (C-B)**
1	**Distribution Plant**				
2	Meters - Commercial	478	82.1	5.8	(76.4)
3	Meters - Residential	478	341.7	457.9	116.2
4	Regulators	474	72.8	68.5	(4.4)
5	Measuring & Regulating Equip	477	88.9	266.0	177.1
6	Mains - Metallic (IGPC)	475	248.1	-	(248.1)
7	Mains - Plastic	475	283.6	1,204.8	921.2
8	Services - Plastic	473	450.2	574.4	124.2
9	**Subtotal**		**1,567.5**	**2,577.4**	**1,009.9**
10	**General Plant**				
11	Land	480	-	-	-
12	Structures & Improvements	482	-	82.9	82.9
13	Furnishing / Office Equipment	483	-	-	-
14	Computer Equipment	490	53.4	13.8	(39.5)
15	Software - Acquired	491	55.8	37.5	(18.3)
16	Tools and Work Equipment	486	70.4	53.3	(17.1)
17	Communication Equipment	488	-	1.8	1.8
18	Vehicles - Transportation Equip	484	180.9	74.2	(106.7)
19	**Subtotal**		**360.4**	**263.5**	**(96.8)**
20	**Intangible Plant**				
21	Franchises	401	-	72.3	72.3
22	**Subtotal**		**-**	**72.3**	**72.3**
23	**Grand Total**		**1,927.9**	**2,913.2**	**985.3**

Account 478 – Meters

The $76K decrease compared to 2022A for commercial meters is due to:

- A further reduction in the number of commercial meters requiring change-out.

The $116K increase compared to 2022A for residential meters is due to:

- The introduction of the residential meter renewal program as meters reached their 10 year end of life. Approximately 1,300 meters were changed out in 2023.

Account 474 – Regulators and Account 477 – Measuring and Regulating Equipment

The $172K increase compared to 2022A is due to:

- The relocation and upgrading of the Belmont regulating station to account for increased growth; and,
- ENGLP's purchase of 190 regulators in 2023 for its renewal program, and installation of 40 regulators for new customers.

Account 475 – Mains

The $248K decrease compared to 2022A for Metallic Mains is due to:

- No capital work completed on the IGPC pipeline in 2023.

The $921K increase compared to 2022A for Plastic Mains is due to:

- An increase in the mains installed from 4,372m in 2022 to 7,916m in 2023. As stated earlier in this Exhibit, ENGLP also introduced Aecon as the contractor to complete mains work after a RFP process was completed where ENGLP's existing contractors did not submit compliant bids that met ENGLP's safety requirements. Aecon's costs were higher than existing contractors but reflected competitively procured rates all whilst ensuring safety as ENGLP's top priority.

- One particular project driving this variance is the Lofthouse dryer connection which consisted of a 2.2 km of 4" plastic - $366K, with a customer contribution of $105K

Account 473 – Services - Plastic

The $124K increase compared to 2022A for plastic services is due to:

- ENGLP introduced Aecon as the contractor to complete services after a RFP process was completed where ENGLP's existing contractors did not submit compliant bids that met ENGLP's safety requirements. Aecon's costs were higher than existing contractors but reflected competitively procured rates all whilst ensuring safety as ENGLP's top priority.

Account 482 – Structures and Equipment

- The $82K increase vs. 2022A is due to the purchase of an automatic vehicle gate for site security and a gas back-up generator to secure SCADA in the event of power outage.

Account 484 – Vehicles – Transportation Equipment

The $107K decrease compared to 2022A is due to:

- Making fewer vehicle purchases in 2023 compared to 2022.

Account 401 – Franchises

The $72K increase compared to 2022A is due to:

- An error in reclassification of assets. This was discovered during the Application preparation process. These assets should have been classified as 491-Software.

Table 2.2.2-5
2023 Actual vs. 2024 Bridge Capital Additions
Net of Contributions
($000's)

	Description	A USoA	B 2023 A	C 2024 Bridge Year	D Difference (C-B)
1	**Distribution Plant**				
2	Meters - Commercial	478	5.8	160.0	154.2
3	Meters - Residential	478	457.9	824.6	366.7
4	Regulators	474	68.5	305.8	237.3
5	Measuring & Regulating Equip	477	266.0	342.4	76.4
6	Mains - Metallic (IGPC)	475	-	300.0	300.0
7	Mains - Plastic	475	1,204.8	2,155.6	950.8
8	Services - Plastic	473	574.4	784.3	209.9
9	**Subtotal**		**2,577.4**	**4,872.7**	**2,295.3**
10	**General Plant**				
11	Land	480	-	-	-
12	Structures & Improvements	482	82.9	-	(82.9)
13	Furnishing / Office Equipment	483	-	-	-
14	Computer Equipment	490	13.8	27.5	13.7
15	Software - Acquired	491	37.5	6.4	(31.1)
16	Tools and Work Equipment	486	53.3	23.4	(29.9)
17	Communication Equipment	488	1.8	12.5	10.7
18	Vehicles - Transportation Equip	484	74.2	102.4	28.2
19	**Subtotal**		**263.5**	**172.3**	**(91.3)**
20	**Intangible Plant**				
21	Franchises	401	72.3	-	(72.3)
22	**Subtotal**		**72.3**	**-**	**(72.3)**
23	**Grand Total**		**2,913.2**	**5,044.9**	**2,131.7**

Account 478 – Meters

The $154K increase compared to 2023A for commercial meters is due to:

- The start of the commercial meter renewal program due to Measurement Canada's end of life criteria.

The $367K increase compared to 2023A for residential meters is due to:

- An increase in residential meters to be replaced in 2024, (2,500 meters) vs 1,300 in 2023.

Account 474 – Regulators and Account 477 – Measuring and Regulating Equipment

The $313K increase compared to 2023A is due to:

- The addition of the station for the new large agricultural customer;
- The replacement of the Aylmer Rogers Road district station; and,
- In 2024, ENGLP purchased 364 regulators for renewals/new customers vs. 230 regulators in 2023. As meters are changed out, there is an increase in regulator change-outs upon testing.

Account 475 – Mains

The $300K increase compared to 2023A for Metallic Mains is due to:

- A cut out and repair of a feature on the IGPC pipeline.

The $950K increase compared to 2023A for Plastic Mains is due to:

- A $1M system access project to increase gas flow to the new large agricultural customer by upgrading 2 km of pipeline from 2" to 6";
- A $700K cost to build a 4" 2Km pipeline to secure additional gas for the new large agricultural customer full phase 1 loading; and,
- Offset by lower than forecast cost on mains additions and extensions than 2023 by $700K. The meters of pipe installed in 2023 was 7,916m. The forecast in 2024 is 3,500m.

Account 473 – Services - Plastic

The $210K increase compared to 2023A for plastic services is due to:

- The planned increase to the number of services forecasted vs. 2023A. In 2023, ENGLP constructed 155 services. The forecast in 2024 is 205.

Account 482 – Structures and Equipment

The $82K decrease compared to 2023A is due to:

- The building updates completed in 2023 whereas none were required in 2024.

2.2.3 2025 Test Year Capital Additions

Table 2.2.3-1
2024 Bridge vs. 2025 Test Capital Additions
Net of Contributions
($000's)

		A	B	C	D
	Description	**USoA**	**2024 B**	**2025 T**	**Difference (C-B)**
1	**Distribution Plant**				
2	Meters - Commercial	478	160.0	157.0	(3.0)
3	Meters - Residential	478	824.6	820.9	(3.8)
4	Regulators	474	305.8	255.7	(50.0)
5	Measuring & Regulating Equip	477	342.4	97.9	(244.5)
6	Mains - Metallic (IGPC)	475	300.0	300.0	-
7	Mains - Plastic	475	2,155.6	1,356.4	(799.2)
8	Services - Plastic	473	784.3	768.9	(15.4)
9	**Subtotal**		4,872.7	3,756.8	(1,115.9)
10	**General Plant**				
11	Land	480	-	-	-
12	Structures & Improvements	482	-	123.5	123.5
13	Furnishing / Office Equipment	483	-	-	-
14	Computer Equipment	490	27.5	57.5	30.0
15	Software - Acquired	491	6.4	10.0	3.6
16	Tools and Work Equipment	486	23.4	23.0	(0.4)
17	Communication Equipment	488	12.5	17.5	5.0
18	Vehicles - Transportation Equip	484	102.4	75.5	(26.9)
19	**Subtotal**		172.3	307.1	134.9
20	**Intangible Plant**				
21	Franchises	401	-	-	-
22	**Subtotal**		-	-	-
23	**Grand Total**		5,044.9	4,063.9	(981.0)

Account 474 – Regulators

The $50K decrease compared to 2024B is due to:

- A decrease in regulators planned to be replaced in 2024 (204) vs. 2025 (196); and,
- A decrease in regulators planned to be added in 2024 (174) vs. 2025 (170).

Account 477 – Measuring and Regulating Equipment

The $244K decrease compared to 2024B is due to:

- No additional station replacement work planned for 2025 Test Year.

Account 475 – Mains

The $799K decrease compared to 2024B for Plastic Mains is due to:

- The 2024 completion of Phase 1 System Access Project for the new large agricultural customer by upgrading 2 km of pipeline from 2" to 6" and building a 4" 2Km pipeline to secure additional gas;
- A decrease in the meters installed from 3,500 metres in 2024 compared to 3,000 meters planned in 2025T; and,

Account 482 – Structures and Equipment

The $123K increase compared to 2024B is due to:

- A new storage building planned to be constructed in the Aylmer distribution office in 2025 to provide storage space for polyethylene pipe, 6" steel pipe and other equipment as necessary.

2.3 Allowance for Working Capital

ENGLP is proposing to include an allowance for working capital as part of its 2025 rate base determination. ENGLP is proposing an allowance of 7.5% based on its non-distribution costs and distribution related OM&A expenses as allowed by the OEB for electricity distributors[3] and as agreed upon during the settlement of the Southern Bruce 10-year custom IR application.[4]

Table 2.3-1 below details the projected working capital, along with a comparison of historical years before a working capital allowance was used.

Table 2.3-1
Working Capital Allowance ($000's)

Working Capital Allowance	2020A	2021A	2022A	2023A	2024B	2025T
Cost of Gas (Non-Distribution)	$6,102	$7,291	$11,004	$12,293	$9,759	$9,992
OM&A	$3,264	$3,316	$3,820	$3,680	$4,162	$4,322
Rate	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%
Total	**$702**	**$795**	**$1,112**	**$1,198**	**$1,044**	**$1,074**

2.4 Capitalization Policy

ENGLP has included EPCOR's Capitalization Procedure for financial and regulatory accounting and reporting. These are attached as Exhibit 2, Tab 2, Schedule 1 and Exhibit 2, Tab 2, Schedule 2, respectively. As a subsidiary of EPCOR, ENGLP will adhere to EPCOR's capitalization procedures and policies.

2.4.1 Capitalization of Overhead

ENGLP has included EPCOR's Capital Overhead Policy as Exhibit 2, Tab 2, Schedule 3. The Policy identifies the types of overhead costs that can be capitalized in the course of acquiring or constructing an item of property, plant and equipment.

[3] Handbook for Utility Rate Applications, Appendix 3: Rate-setting Policies, October 13, 2016, page 6.

[4] Decision on settlement proposal and procedural order no. 6, EB-2018-0264, October 3, 2019, page 23/46.

Capital overhead includes the cost of certain supporting functions that are capitalized and charged to capital projects. These functions include: senior management oversight, supervision, project governance, accounting, and dedicated health and safety resources. Capital overhead recoveries reflect a transfer from operating expenses to capital projects as indirect costs. The capital overhead allocation is meant to allocate employee costs, for employees who support capital projects and do not directly charge time to a specific capital project.

The capital overhead rate will be calculated by dividing the capital overhead cost pool by the total direct labour transfers to capital projects for the business unit. Direct labour will be used as the cost driver because this more accurately assigns higher overhead to projects that require the most internal labour and oversight for which the overhead pool is meant to cover. Table 2.4.1-1 below shows the forecasted capitalized overhead for 2023-2025.

Table 2.4.1-1

Capitalized Overhead on Self-Constructed Assets ($000's)

	A	B	C
Capital Cost Type	**2023 A**	**2024 Bridge**	**2025 Test**
Capitalized Overheads	$183.6	$240.6	$287.9

2.4.2 Burden Rates

EPCOR's burden rates are provided at the corporate level for all of EPCOR's business units, including Aylmer. The burden rate of 41.9% is used by ENGLP to recover the employee's benefits (e.g., CPP, EI, medical and dental benefits and disability), vacation, statutory holidays and shift differentials when salary and labor costs are charged to operating areas or capital projects. In other words, the burden rate is applied to salary and labor costs. ENGLP has included EPCOR's Burden Procedure and Policy (FA-011) as Exhibit 2, Tab 2, Schedule 4.

This value is a reduction from the burden rate of 44% as used in the previous filing (Exhibit 2.4.2, EB-2018-0336). The reduction in rates can be attributed to better performance on the long term disability plan and a decrease in pension plan percentage.

2.5 Capital Expenditures

Table 2.5-1 below provides a summary of the capital expenditures from 2020T to 2029U.

Table 2.5-1
2020-2029 Capital Expenditures
($ thousands)

($000's)	2020T	2020A	2021A	2022A	2023A	2024B	2025T	2026U	2027U	2028U	2029U
System Access	523	1,718	1,906	1,736	1,536	3,292	1,954	2,731	1,665	1,750	1,830
System Renewal	490	23	40	383	673	1,653	1,460	1,567	912	930	567
System Service	269	604	143	99	80	25	450	40	405	409	50
General Plant	130	120	135	291	250	147	272	152	160	164	168
Total Expenditure	**1,412**	**2,465**	**2,223**	**2,509**	**2,539**	**5,117**	**4,136**	**4,490**	**3,142**	**3,253**	**2,615**
Capital Contributions	72	131	224	91	173	72	72	477	75	79	83
Net	**1,340**	**2,333**	**1,999**	**2,418**	**2,366**	**5,045**	**4,064**	**4,013**	**3,066**	**3,174**	**2,532**

2.5.1 Key Drivers

ENGLP has organized its forecast capital expenditures in accordance with the work program categories in the Board's "Filing Requirements for Electricity Distribution and Transmission Applications, Consolidated Distribution System Plan Filing Requirements". Those categories are:

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. 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 are the lifecycle replacement distribution assets, or refurbishment to extend the original service life, ensuring system integrity and safe operation;

c) **System Service** - investments are modifications to the distribution system to improve reliability, mitigate risk or introduce efficiencies and ensure that performance goals and objectives are met; and

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, such as fleet, tools and equipment, buildings and computers and software.

2.5.2 Grants and Customer Contributions

As outlined in the Board Report (EB 2008-0408):

> *"For regulatory reporting and rate making purposes the amount of customer contributions will be treated as deferred revenue to be included as an offset to rate base and amortized to income over the life of the facility to which it relates".*

Consistent with the Board's guidance, ENGLP records customer contributions as deferred revenue, which is amortized over the life of the related asset. For the purpose of this Application, capital contributions are included as an offset to rate base and the related amortized revenue as an offset to depreciation expense.

The contributions in Table 2.5-1 relate to contributions from customers relating to new service additions.

2.5.3 Treatment of Construction Work in Progress

Consistent with EPCOR's capitalization policy (FA-004, Exhibit 2, Tab 2, Schedule 1), the costs associated with construction of the fixed assets that are not yet in service or incomplete are recognized in the Construction Work in Progress ("**CWIP**") account. Interest during construction ("**IDC**") accumulates at the OEB prescribed rate for the time the qualified capital work is incomplete. In its application of the capitalization policy, ENGLP determines a qualifying project when it is an individual project/asset, which has a construction duration of six months or longer and a cost of $100,000 or greater. ENGLP notes that IDC has not been included for any capital expenditures to date or in the 2024 Bridge Year and 2025 Test Year. Fixed assets that are substantially complete and available for use are removed from CWIP.

Construction on the budgeted capital projects is expected to begin and be completed within the same calendar year. Therefore, the capital expenditures are expected to be added into and removed from the CWIP account within the same year. Consistent with its previous filing, ENGLP does not anticipate any CWIP balances at the end of each year from 2025 to 2029 as its annual construction are expected to be completed within a construction season, which typically runs from April to November. The fixed assets coming into service will have gross book values equaling their capital expenditure and the associated IDC when applicable.

2.5.4 Previous Utility System Plan Variance Analysis

ENGLP's previous cost of service filing included a USP for the period of 2020-2024. This section provides the variance explanations between the previously filed USP and the actions during the years of 2020-2024. Variance explanations are provided only where actuals diverged from plan by greater than 15%.

2020 USP vs. Actual

2020 ($000's)	**Plan**	**Actual**	**Var**
System Access	523	1,718	228%
System Renewal	490	23	-95%
System Service	269	604	125%
General Plant	130	120	-7%
Total Expenditure	**1,412**	**2,465**	**75%**
Capital Contributions	72	131	82%
Net	**1,340**	**2,333**	**74%**

The 228% variance between plan and actuals for system access is due to the use of contractors to install services and mains at higher cost than was assumed within the USP. Many of the services and mains required complex road bores and ENGLP does not have the tooling for this scope of work. There was also a $253K unplanned investment into the Village of Salford community expansion. In addition to this, the USP had some mains, meters and regulator scope categorized as system renewal, but almost all mains, meters and regulators were system access investments in 2020.

The -95% variance between plan and actuals for system renewal was due to the timing of expiration of end of life for meters. In order to align with the expiration, this spend is incurred in the years 2023/24/25 based on the 10-year useful life of the meters. In addition, the USP had assumed some volume of mains and regulators would be renewed in 2020, but this investment was system access.

The 125% variance between plan and actuals for system services was due to the upgrade of the SCADA system that was planned for 2019, but completed in 2020 ($391K). Further, there were increased costs in 2020 ($114K) associated with the completion of the Lakeview station and installation of 6inch PE pipe instead of 4inch coming out of the station in order to meet future peak demand volume requirements.

2021 USP vs. Actual

2021 ($000's)	Plan	Actual	Var
System Access	516	1,906	270%
System Renewal	501	40	-92%
System Service	187	143	-24%
General Plant	319	135	-58%
Total Expenditure	**1,522**	**2,223**	**46%**
Capital Contributions	65	224	244%
Net	**1,457**	**1,999**	**37%**

The 270% increase compared to USP for system access is due to the use of third-party contractors to install services and mains at higher cost than was assumed within the USP. Many of the services and mains required complex road bores for which ENGLP does not have the tooling for this scope of work. There was also a grain dryer customer connected at a cost of $300K via a 4” main extension that was not forecasted in the USP, and a $115K 4” main extension to connect the Village of Salford which was also not forecasted in the USP. In addition to this, the USP had some mains, meters and regulator scope categorized as system renewal, but almost all mains, meters and regulators were system access investments.

The -92% variance between plan and actuals for system renewal was due to the timing of expiration of end of life for meters. In order to align with the expiration, this spend is incurred in the years 2023/24/25 based on the 10-year useful life of the meters. In addition, the USP had assumed some volume of mains and regulators would be renewed in 2021, but this was all categorized as system access.

The -24% variance between plan and actuals for system services was due to less spend incurred on SCADA and GIS mapping than planned.

The -58% variance between plan and actuals for the general plant is due to not recertifying the CNG gas refueling station given ENGLP stopped buying CNG vehicles. ENGLP also did not replace as many vehicles as planned in the USP.

2022 USP vs. Actual

2022 ($000's)	Plan	Actual	Var
System Access	527	1,736	229%
System Renewal	512	383	-25%
System Service	190	99	-48%
General Plant	76	291	283%
Total Expenditure	**1,305**	**2,509**	**92%**
Capital Contributions	66	91	37%
Net	**1,239**	**2,418**	**95%**

The 229% increase compared to the USP for system access is due to the use of contractors to install services and mains at higher cost than was assumed within the USP. Many of the services and mains complex required road bores and ENGLP does not have the tooling for this scope of work. Additionally, halfway through 2022, after completing a competitive procurement process for a contractor that met ENGLP's enhanced construction standards stemming from a few operational incidents, ENGLP introduced a new contractor to the Aylmer region. In meeting ENGLP's enhanced standards, the cost to serve increased. In addition, although the USP had some mains, meters and regulator scope categorized as system renewal, the majority of mains, meters and regulators were system access investments.

The -25% decrease between plan and actuals for system renewal was due to the spread of budget required to change out meters. This spend is incurred more specifically in the years 2023/24/25 based on the 10-year life of the meters. Moreover, the USP had assumed some volume of mains and regulators would be renewed in 2022, but this was all categorized as system access due to the main driver of the mains investment scope being to add customers or create access. In 2022, the Belmont Regulating Station was upgraded and moved, and the IGPC pipeline had a repair completed. This cut out and repair scope of work cost $248K.

The -48% variance between plan and actuals for system services was due to less SCADA investments than planned.

The 283% variance between plan and actuals for the general plant is due the renovations completed on the ENGLP building to accommodate additional staff and improve the functionality of the facility. In addition, there was an acquisition of one forklift and two 4-wheel drive trucks to replace service vans in order to improve employee safety.

2023 USP vs. Actual

2023 ($000's)	Plan	Actual	Var
System Access	536	1,536	187%
System Renewal	521	673	29%
System Service	194	80	-59%
General Plant	78	250	221%
Total Expenditure	**1,329**	**2,539**	**91%**
Capital Contributions	68	173	155%
Net	**1,261**	**2,366**	**88%**

The 187% variance between plan and actuals for system access is due to the use of contractors to install services and mains at higher cost than was assumed within the USP. One particular project driving this variance is the Lofthouse Dryer connection, which consists of a 2.2 km of 4" plastic. This work cost $366K with a contribution from Lofthouse of $105K. In addition to this, the USP had some mains scope categorized as system renewal, but almost all mains were system access investments.

The 29% variance between plan and actuals for system renewal was due to the requirement to start the change out of customer meters as they reached the 10 year end of life assigned by Measurement Canada. 1,300 meters were replaced in 2023. The variance would have been larger given some of the mains categorized as system renewal in the USP were actually system access investments as detailed above.

The -58% variance between plan and actuals for system services was due to lower investment in SCADA than planned.

The 221% variance between plan and actuals for the general plant is due to: the addition of a vehicle security gate installed in the ENGLP yard; a hotel desk area was built; a shower was installed; Green Button was implemented; and a service van was replaced with a 4-wheel drive truck to improve employee safety.

2024 USP vs. Actual

2024 ($000's)	**Plan**	**Forecast**	**Var**
System Access	548	3,292	501%
System Renewal	532	1,653	211%
System Service	198	25	-87%
General Plant	79	147	86%
Total Expenditure	**1,357**	**5,117**	**277%**
Capital Contributions	69	72	5%
Net	**1,288**	**5,045**	**292%**

The 501% variance between plan and actuals for system access is due to unplanned material projects including the upgrade of 2Km of pipeline from 2" to 6" to feed the new large agricultural customer ($1M), the construction of 2Km of 4" pipeline to secure additional gas for the new large agricultural customer ($700K), and the construction of 400m of 4" pipeline to Butters Lane Farms ($197K). Further, ENGLP used contractors to install services and mains at higher cost than was assumed within the USP. Additionally, the USP had some mains scope categorized as system renewal, but almost all mains were system access investments.

The 211% variance between plan and actuals for system renewal was due to the requirement to start the change out of customer meters as they reached the 10 year end of life assigned by Measurement Canada. 2,500 meters are being replaced in 2024. The USP system renewal estimates in 2024 didn't represent the requirement for 2,500 meters. As mentioned above, the total meter renewal budget was spread over 5 years, whereas the actuals have been clustered in the years 2023/24 and in 2025. The variance would have been larger given some of the mains scope categorized as system renewal in the USP were actually system access investments as mentioned above.

The -87% variance between plan and actuals for system services was due to lower investment in SCADA than planned.

The 86% increase between plan and actuals for General Plant is due the purchase of a 4 wheel drive truck to replace a service van, and the purchase of a trailer to haul material.

2.6 Utility System Plan (USP)

ENGLP's USP has been included as in this Exhibit as Exhibit 2, Tab 3, Schedule 1.

2.6.1 Asset Management Plan

ENGLP's Asset Management Plan has been included as Exhibit 2, Tab 3, Schedule 1 in this Exhibit (embedded within the USP).

2.6.2 Customer Connection Policy

As stated in the E.B.O. 188 Guidelines[5]:

Part of the utilities' management of distribution system expansion will be the provision of common customer connection policies. These will include policies relating to service line fees, customer contributions to otherwise financially unfeasible projects and for projects dominated by one or more large volume customers.

ENGLP has developed a policy in alignment with OEB guidelines and included it as part of this application. This is the first formal Customer Connection policy that ENGLP has prepared and submitted to the OEB.

The purpose of this Policy is to present the current procedures and policies for determining the feasibility of the Utility's system expansion and community expansion projects. The Policy includes sections regarding the Utility's Customer Connection Policies, Customer Contribution and Refund Policies and Method for Economic Feasibility Assessment.

ENGLP's Customer Connection Policy has been included as Exhibit 2, Tab 3, Schedule 2 in this Exhibit.

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[5] Appendix B – Ontario Energy Board Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario, January 30, 1998, paragraph 268.

2.7 Service Quality and Reliability

Consistent with the Board's requirements, ENGLP has provided the last 5 years of its historical service quality performance in Table 2.7.1 below.

Table 2.7-1

2019 – 2023 Service Quality Measures(%)

Service Quality Measure	A OEB Standard	B 2019	C 2020	D 2021	E 2022	F 2023
1 Call Answering	minimum 75%	98.5	96.0	89.3	89.4	91.9
2 Call Abandon Rate	not exceed 10%	1.5	4.0	4.1	3.1	2.3
3 Meter Reading	not exceed 0.5%	0	0	0	0.01	0.002
4 Appointments Met	minimum 85%	99.8	99.5	99.8	99.9	98.0
5 Reschedule Appointments	100%	100	100	100	100	100
6 Emergency Call Response	minimum 90%	98.8	97.5	97.6	98.5	97.9
7 Days to Provide Written Response	minimum 80%	100	100	100	100	100
8 Days to Reconnect	minimum 85%	100	100	100	95.7	100

ENGLP notes that the utility has consistently performed above the Board's targets. As such, no corrective action is currently required. ENGLP plans to continue performing at or above the Board's standard.

2.7.1 Reliability Performance

ENGLP's operations and maintenance 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 the asset lifecycle until such time that the asset has reached a condition requiring refurbishment or replacement.

Recently, ENGLP has utilized GIS and SCADA to provide a better overall understanding of its assets. This will lead to more efficient and optimized design, maintenance and investment activities going forward. Inspection, maintenance and testing data will be input into the GIS as attribute information for each piece of the system. Increased and accurate operating data will be collected through GIS and be made available for engineering analysis and service quality reporting.

Further, ENGLP's Integrity Management Program contributes to extending the useful life of assets by identifying condition issues prior to occurrences of incidents. The weekly, monthly and annual inspection activities reduces the probability of pipeline failures and unplanned asset integrity issues. The program includes procedures to monitor for conditions that can lead to failures and includes a description of ENGLP's commitment to assess risks, identify risk reduction approaches and monitor results.

Over the past five years (2019-2024), ENGLP has proactively taken steps to ensure the reliability, safety and performance of its natural gas operating system in Aylmer. A dashboard was created to monitor the progress of all inspection and maintenance activities, and to ensure they are completed annually.

The following activities are performed annually:

1. Annual Public Building Survey in the winter time period, when frost in the ground, to check for underground leaks migrating to public buildings;
2. Annual inspection and maintenance of:
    a. Regulating, District, Customer and PFM Stations;

b. Poly Valves (underground) and above ground valves to ensure they are operable in emergency situations; and,

c. all mercury calibrating equipment in the field;

3. Annual Leak Survey is conducted on both steel and plastic pipelines and repairs are accordingly performed depending on the pipeline's classification;

4. Corrosion reads are also conducted to ensure that the steel pipe is properly cathodically protected;

5. Depth of Cover of pipelines are checked to ensure they are at the required depth to prevent pipe damages due to digging by 3rd party contractors; and,

6. The pipeline system is modelled annually to ensure an adequate system capacity to continue to provide safe, reliable and uninterrupted supply of natural gas within all areas of ENGLP's system to residential, industrial and commercial customers.

Fixed Asset Continuity Schedule

Appendix 2C
Fixed Asset Continuity Schedule ($)

Accounting Standard: MIFRS
Year: 2020

			Cost				Accumulated Depreciation / Contributions				
CCA Class [2]	OEB Account [3]	Description [3]	Opening Balance [8]	Additions [4]	Disposals [6]	Closing Balance	Opening Balance [8]	Additions	Disposals [6]	Closing Balance	Net Book Value
50	488	Communication Equipment	$ 198,690	$ 47,389		$ 246,079	-$ 166,941	-$ 4,931		-$ 171,871	$ 74,208
50	490	Computer Equipment	$ 409,968	$ 29,668		$ 439,636	-$ 325,532	-$ 57,723		-$ 383,255	$ 56,381
51	499	Contributions - Mains - Metallic (IGPC)	-$ 334,481	-$ 41,807		-$ 376,288	$ 14,945	$ 3,877		$ 18,822	-$ 357,466
51	499	Contributions - Mains Plastic	-$ 67,088	-$ 25,101		-$ 92,189	$ 1,087	$ 1,814		$ 2,901	-$ 89,289
51	499	Contributions - Services Metal	-$ 13,208	$ -		-$ 13,208	$ 953	$ 332		$ 1,285	-$ 11,923
51	499	Contributions - Services Plastic	-$ 116,753	-$ 64,425		-$ 181,178	$ 3,497	$ 3,735		$ 7,233	-$ 173,946
	401	Franchise & Consents	$ 767,862	$ 2,536		$ 770,399	-$ 381,016	-$ 31,492		-$ 412,508	$ 357,891
	483	Furnishing / Office Equipment	$ 112,536	$ 37,791		$ 150,327	-$ 95,195	-$ 3,008		-$ 98,203	$ 52,123
	480	Land	$ 71,700	$ -		$ 71,700	$ -	$ -		$ -	$ 71,700
51	475	Mains - Metallic	$ -	$ -		$ -	$ -	$ -		$ -	$ -
51	475	Mains - Metallic (IGPC)	$ 5,982,227	$ 618		$ 5,982,844	-$ 2,948,415	-$ 69,947		-$ 3,018,361	$ 2,964,483
51	475	Mains - Plastic	$ 12,527,482	$ 1,239,921		$ 13,767,402	-$ 5,918,625	-$ 252,942		-$ 6,171,567	$ 7,595,836
8	477	Measuring & Regulating Equip	$ 1,048,911	$ 656,132		$ 1,705,043	-$ 890,620	-$ 28,039		-$ 918,658	$ 786,385
8	477	Measuring & Regulating Equip (IGPC)	$ 576,367	$ -		$ 576,367	-$ 40,456	-$ 21,087		-$ 61,543	$ 514,824
51	478	Meters - Commercial	$ 1,625,677	$ 82,220		$ 1,707,897	-$ 770,455	-$ 63,773		-$ 834,228	$ 873,668
51	478	Meters - IGPC	$ 14,139	$ -		$ 14,139	-$ 6,061	-$ 8,079		-$ 14,139	$ -
51	478	Meters - Residential	$ 1,581,802	$ 180,933		$ 1,762,735	-$ 749,101	-$ 283,219		-$ 1,032,320	$ 730,415
8	474	Regulators	$ 563,985	$ 27,242		$ 591,227	-$ 381,233	-$ 11,651		-$ 392,884	$ 198,343
51	473	Services - Plastic	$ 4,296,941	$ 535,031		$ 4,831,972	-$ 2,870,317	-$ 47,548		-$ 2,917,865	$ 1,914,108
12	491	Software - Acquired	$ 562,696	$ 91,365		$ 654,061	-$ 403,757	-$ 28,647		-$ 432,404	$ 221,656
1	482	Structures & Improvements	$ 699,633	$ -		$ 699,633	-$ 294,134	-$ 11,304		-$ 305,439	$ 394,194
8	486	Tools and Work Equipment	$ 754,974	$ -		$ 754,974	-$ 567,556	-$ 17,213		-$ 584,769	$ 170,205
10	485	Vehicle - Heavy Work Equip	$ 33,033	$ -		$ 33,033	-$ 2,753	-$ 2,291		-$ 5,044	$ 27,989
10	484	Vehicles - Transportation Equip	$ 413,583	$ 63,894		$ 477,477	-$ 221,118	-$ 47,659		-$ 268,776	$ 208,700
		Sub-Total	**$ 31,710,675**	**$ 2,863,407**	**$ -**	**$ 34,574,082**	**-$ 17,012,801**	**-$ 980,794**	**$ -**	**-$ 17,993,595**	**$ 16,580,487**
		Less Other Non Rate-Regulated Utility Assets *(input as negative)*				$ -				$ -	$ -
		Total PP&E for Rate Base Purposes	**$ 31,710,675**	**$ 2,863,407**	**$ -**	**$ 34,574,082**	**-$ 17,012,801**	**-$ 980,794**	**$ -**	**-$ 17,993,595**	**$ 16,580,487**
		Construction Work In Progress	$ 623,154	-$ 491,109		$ 132,045				$ -	$ 132,045
		Total PP&E	**$ 32,333,829**	**$ 2,372,297**	**$ -**	**$ 34,706,127**	**-$ 17,012,801**	**-$ 980,794**	**$ -**	**-$ 17,993,595**	**$ 16,712,531**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]						$ 151,841			
		Total Net Depreciation						**-$ 828,953**			

Accounting Standard: MIFRS
Year: 2021

			Cost				Accumulated Depreciation / Contributions				
CCA Class [2]	OEB Account [3]	Description [3]	Opening Balance [8]	Additions [4]	Disposals [6]	Closing Balance	Opening Balance [8]	Additions	Disposals [6]	Closing Balance	Net Book Value
50	488	Communication Equipment	$ 246,079	$ 65,110		$ 311,189	-$ 171,871	-$ 13,021		-$ 184,893	$ 126,297
50	490	Computer Equipment	$ 439,636	$ 74,281		$ 513,917	-$ 383,255	-$ 50,205		-$ 433,460	$ 80,457
51	499	Contributions - Mains - Metallic (IGPC)	-$ 376,288	$ -		-$ 376,288	$ 18,822	$ 7,643		$ 26,464	-$ 349,824
51	499	Contributions - Mains Plastic	-$ 92,189	-$ 135,807		-$ 227,996	$ 2,901	$ 3,702		$ 6,602	-$ 221,394
51	499	Contributions - Services Metal	-$ 13,208	$ -		-$ 13,208	$ 1,285	$ 332		$ 1,616	-$ 11,592
51	499	Contributions - Services Plastic	-$ 181,178	-$ 88,110		-$ 269,288	$ 7,233	$ 5,654		$ 12,887	-$ 256,401
	401	Franchise & Consents	$ 770,399	$ -		$ 770,399	-$ 412,508	-$ 31,619		-$ 444,127	$ 326,272
	483	Furnishing / Office Equipment	$ 150,327	$ 50,393		$ 200,720	-$ 98,203	-$ 9,307		-$ 107,511	$ 93,209

	480	Land	$ 71,700	$ 10,953		$ 82,653	$ -	$ -		$ -	$ 82,653
51	475	Mains - Metallic	$ -	$ -		$ -	$ -	$ -		$ -	$ -
51	475	Mains - Metallic (IGPC)	$ 5,982,844	$ -		$ 5,982,844	-$ 3,018,361	-$ 80,110		-$ 3,098,471	$ 2,884,373
51	475	Mains - Plastic	$ 13,767,402	$ 832,979		$ 14,600,382	-$ 6,171,567	-$ 271,860		-$ 6,443,427	$ 8,156,955
8	477	Measuring & Regulating Equip	$ 1,705,043	$ 38,743		$ 1,743,787	-$ 918,658	-$ 32,658		-$ 951,316	$ 792,471
8	477	Measuring & Regulating Equip (IGPC)	$ 576,367	$ -		$ 576,367	-$ 61,543	-$ 21,087		-$ 82,629	$ 493,738
51	478	Meters - Commercial	$ 1,707,897	$ 130,448		$ 1,838,344	-$ 834,228	-$ 69,090		-$ 903,318	$ 935,026
51	478	Meters - IGPC	$ 14,139	$ -		$ 14,139	-$ 14,139	$ -		-$ 14,139	$ -
51	478	Meters - Residential	$ 1,762,735	$ 60,744		$ 1,823,479	-$ 1,032,320	-$ 142,272		-$ 1,174,591	$ 648,887
8	474	Regulators	$ 591,227	$ 75,197		$ 666,424	-$ 392,884	-$ 14,842		-$ 407,725	$ 258,699
51	473	Services - Plastic	$ 4,831,972	$ 570,464		$ 5,402,436	-$ 2,917,865	-$ 64,776		-$ 2,982,640	$ 2,419,796
12	491	Software - Acquired	$ 654,061	$ 975		$ 655,036	-$ 432,404	-$ 33,234		-$ 465,638	$ 189,398
1	482	Structures & Improvements	$ 699,633	$ -		$ 699,633	-$ 305,439	-$ 11,304		-$ 316,743	$ 382,890
8	486	Tools and Work Equipment	$ 754,974	$ 15,640		$ 770,614	-$ 584,769	-$ 17,734		-$ 602,503	$ 168,111
10	485	Vehicle - Heavy Work Equip	$ 33,033	$ -		$ 33,033	-$ 5,044	-$ 2,291		-$ 7,335	$ 25,698
10	484	Vehicles - Transportation Equip	$ 477,477	$ 38,553		$ 516,029	-$ 268,776	-$ 52,780		-$ 321,557	$ 194,472
		Sub-Total	**$ 34,574,082**	**$ 1,740,564**	**$ -**	**$ 36,314,646**	**-$ 17,993,595**	**-$ 900,859**	**$ -**	**-$ 18,894,454**	**$ 17,420,192**
		***Less Other Non Rate-Regulated Utility Assets** (input as negative)*	$ -			$ -	$ -			$ -	$ -
		Total PP&E for Rate Base Purposes	**$ 34,574,082**	**$ 1,740,564**	**$ -**	**$ 36,314,646**	**-$ 17,993,595**	**-$ 900,859**	**$ -**	**-$ 18,894,454**	**$ 17,420,192**
		Construction Work In Progress	$ 132,045	$ 399,054		$ 531,098				$ -	$ 531,098
		Total PP&E	**$ 34,706,127**	**$ 2,139,617**	**$ -**	**$ 36,845,744**	**-$ 17,993,595**	**-$ 900,859**	**$ -**	**-$ 18,894,454**	**$ 17,951,290**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total Net Depreciation						**-$ 900,859**			

Accounting Standard MIFRS
Year **2022**

			Cost				Accumulated Depreciation / Contributions				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance [8]**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance [8]**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
50	488	Communication Equipment	$ 311,189	$ -		$ 311,189	-$ 184,893	-$ 10,851		-$ 195,743	$ 115,446
50	490	Computer Equipment	$ 513,917	$ 53,353		$ 567,270	-$ 433,460	-$ 33,004		-$ 466,463	$ 100,807
51	499	Contributions - Mains - Metallic (IGPC)	-$ 376,288	$ -		-$ 376,288	$ 26,464	$ 7,643		$ 34,107	-$ 342,181
51	499	Contributions - Mains Plastic	-$ 227,996	-$ 55,901		-$ 283,897	$ 6,602	$ 5,918		$ 12,520	-$ 271,377
51	499	Contributions - Services Metal	-$ 13,208	$ -		-$ 13,208	$ 1,616	$ 332		$ 1,948	-$ 11,260
51	499	Contributions - Services Plastic	-$ 269,288	-$ 23,070		-$ 292,358	$ 12,887	$ 7,050		$ 19,937	-$ 272,421
	401	Franchise & Consents	$ 770,399	$ -		$ 770,399	-$ 444,127	-$ 31,619		-$ 475,746	$ 294,653
	483	Furnishing / Office Equipment	$ 200,720	$ -		$ 200,720	-$ 107,511	-$ 7,628		-$ 115,138	$ 85,582
	480	Land	$ 82,653	$ -		$ 82,653	$ -	$ -		$ -	$ 82,653
51	475	Mains - Metallic	$ -	$ -		$ -	$ -	$ -		$ -	$ -
51	475	Mains - Metallic (IGPC)	$ 5,982,844	$ 248,130		$ 6,230,974	-$ 3,098,471	-$ 81,363		-$ 3,179,834	$ 3,051,140
51	475	Mains - Plastic	$ 14,600,382	$ 339,462		$ 14,939,843	-$ 6,443,427	-$ 283,682		-$ 6,727,108	$ 8,212,735
8	477	Measuring & Regulating Equip	$ 1,743,787	$ 88,922		$ 1,832,709	-$ 951,316	-$ 34,521		-$ 985,837	$ 846,871
8	477	Measuring & Regulating Equip (IGPC)	$ 576,367	$ -		$ 576,367	-$ 82,629	-$ 21,087		-$ 103,716	$ 472,651
51	478	Meters - Commercial	$ 1,838,344	$ 82,130		$ 1,920,475	-$ 903,318	-$ 74,404		-$ 977,722	$ 942,752
51	478	Meters - IGPC	$ 14,139	$ -		$ 14,139	-$ 14,139	$ -		-$ 14,139	$ -
51	478	Meters - Residential	$ 1,823,479	$ 341,693		$ 2,165,172	-$ 1,174,591	-$ 154,416		-$ 1,329,007	$ 836,164
8	474	Regulators	$ 666,424	$ 72,839		$ 739,263	-$ 407,725	-$ 17,912		-$ 425,638	$ 313,626
51	473	Services - Plastic	$ 5,402,436	$ 473,315		$ 5,875,751	-$ 2,982,640	-$ 75,198		-$ 3,057,839	$ 2,817,912
12	491	Software - Acquired	$ 655,036	$ 55,763		$ 710,799	-$ 465,638	-$ 35,973		-$ 501,612	$ 209,187
1	482	Structures & Improvements	$ 699,633	$ -		$ 699,633	-$ 316,743	-$ 11,304		-$ 328,047	$ 371,586
8	486	Tools and Work Equipment	$ 770,614	$ 70,392		$ 841,006	-$ 602,503	-$ 20,365		-$ 622,868	$ 218,138
10	485	Vehicle - Heavy Work Equip	$ 33,033	$ -		$ 33,033	-$ 7,335	-$ 2,291		-$ 9,627	$ 23,406
10	484	Vehicles - Transportation Equip	$ 516,029	$ 180,866		$ 696,895	-$ 321,557	-$ 61,807		-$ 383,364	$ 313,531
		Sub-Total	**$ 36,314,646**	**$ 1,927,894**	**$ -**	**$ 38,242,540**	**-$ 18,894,454**	**-$ 936,484**	**$ -**	**-$ 19,830,938**	**$ 18,411,602**
		***Less Other Non Rate-Regulated Utility Assets** (input as negative)*				$ -				$ -	$ -
		Total PP&E for Rate Base Purposes	**$ 36,314,646**	**$ 1,927,894**	**$ -**	**$ 38,242,540**	**-$ 18,894,454**	**-$ 936,484**	**$ -**	**-$ 19,830,938**	**$ 18,411,602**
		Construction Work In Progress	$ 531,098	$ 348,566		$ 879,664				$ -	$ 879,664
		Total PP&E	**$ 36,845,744**	**$ 2,276,460**	**$ -**	**$ 39,122,204**	**-$ 18,894,454**	**-$ 936,484**	**$ -**	**-$ 19,830,938**	**$ 19,291,266**

		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]	
		Total Net Depreciation	**-$ 936,484**

Accounting Standard MIFRS
Year **2023**

			Cost				Accumulated Depreciation / Contributions				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance [8]**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance [8]**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
50	488	Communication Equipment	$ 311,189	$ 1,814		$ 313,003	-$ 195,743	-$ 10,911		-$ 206,655	$ 106,349
50	490	Computer Equipment	$ 567,270	$ 13,830		$ 581,101	-$ 466,463	-$ 40,071		-$ 506,535	$ 74,566
51	499	Contributions - Mains - Metallic (IGPC)	-$ 376,288	$ -		-$ 376,288	$ 34,107	$ 7,643		$ 41,750	-$ 334,538
51	499	Contributions - Mains Plastic	-$ 283,897	-$ 8,599		-$ 292,496	$ 12,520	$ 6,663		$ 19,184	-$ 273,313
51	499	Contributions - Services Metal	-$ 13,208	$ -		-$ 13,208	$ 1,948	$ 332		$ 2,279	-$ 10,929
51	499	Contributions - Services Plastic	-$ 292,358	-$ 164,672		-$ 457,030	$ 19,937	$ 9,406		$ 29,343	-$ 427,686
	401	Franchise & Consents	$ 770,399	$ 72,268		$ 842,667	-$ 475,746	-$ 33,425		-$ 509,171	$ 333,496
	483	Furnishing / Office Equipment	$ 200,720	$ -		$ 200,720	-$ 115,138	-$ 7,628		-$ 122,766	$ 77,954
	480	Land	$ 82,653	$ -		$ 82,653	$ -	$ -		$ -	$ 82,653
51	475	Mains - Metallic	$ -	$ -		$ -	$ -	$ -		$ -	$ -
51	475	Mains - Metallic (IGPC)	$ 6,230,974	$ -		$ 6,230,974	-$ 3,179,834	-$ 78,663		-$ 3,258,497	$ 2,972,477
51	475	Mains - Plastic	$ 14,939,843	$ 1,213,393		$ 16,153,236	-$ 6,727,108	-$ 301,095		-$ 7,028,203	$ 9,125,033
8	477	Measuring & Regulating Equip	$ 1,832,709	$ 266,020		$ 2,098,729	-$ 985,837	-$ 41,014		-$ 1,026,852	$ 1,071,877
8	477	Measuring & Regulating Equip (IGPC)	$ 576,367			$ 576,367	-$ 103,716	-$ 21,087		-$ 124,802	$ 451,565
51	478	Meters - Commercial	$ 1,920,475	$ 5,775		$ 1,926,249	-$ 977,722	-$ 76,602		-$ 1,054,324	$ 871,925
51	478	Meters - IGPC	$ 14,139	$ -		$ 14,139	-$ 14,139	$ -		-$ 14,139	$ -
51	478	Meters - Residential	$ 2,165,172	$ 457,941		$ 2,623,113	-$ 1,329,007	-$ 176,445		-$ 1,505,453	$ 1,117,661
8	474	Regulators	$ 739,263	$ 68,482		$ 807,746	-$ 425,638	-$ 21,446		-$ 447,083	$ 360,662
51	473	Services - Plastic	$ 5,875,751	$ 739,081		$ 6,614,832	-$ 3,057,839	-$ 90,417		-$ 3,148,256	$ 3,466,577
12	491	Software - Acquired	$ 710,799	$ 37,488		$ 748,287	-$ 501,612	-$ 40,636		-$ 542,247	$ 206,039
1	482	Structures & Improvements	$ 699,633	$ 82,929		$ 782,562	-$ 328,047	-$ 12,100		-$ 340,147	$ 442,414
8	486	Tools and Work Equipment	$ 841,006	$ 53,272		$ 894,279	-$ 622,868	-$ 24,250		-$ 647,118	$ 247,161
10	485	Vehicle - Heavy Work Equip	$ 33,033	$ -		$ 33,033	-$ 9,627	-$ 2,291		-$ 11,918	$ 21,115
10	484	Vehicles - Transportation Equip	$ 696,895	$ 74,199		$ 771,093	-$ 383,364	-$ 74,840		-$ 458,205	$ 312,889
		Sub-Total	**$ 38,242,540**	**$ 2,913,221**	**$ -**	**$ 41,155,761**	**-$ 19,830,938**	**-$ 1,028,878**	**$ -**	**-$ 20,859,816**	**$ 20,295,945**
		Less Other Non Rate-Regulated Utility Assets ***(input as negative)***				$ -				$ -	$ -
		Total PP&E for Rate Base Purposes	**$ 38,242,540**	**$ 2,913,221**	**$ -**	**$ 41,155,761**	**-$ 19,830,938**	**-$ 1,028,878**	**$ -**	**-$ 20,859,816**	**$ 20,295,945**
		Construction Work In Progress	$ 879,664	-$ 691,217		$ 188,447				$ -	$ 188,447
		Total PP&E	**$ 39,122,204**	**$ 2,222,005**	**$ -**	**$ 41,344,209**	**-$ 19,830,938**	**-$ 1,028,878**	**$ -**	**-$ 20,859,816**	**$ 20,484,392**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total Net Depreciation						**-$ 1,028,878**			

Accounting Standard MIFRS
Year **2024 BRIDGE**

			Cost				Accumulated Depreciation / Contributions				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance [8]**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance [8]**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
50	488	Communication Equipment	$ 313,003	$ 12,530		$ 325,533	-$ 206,655	-$ 11,663		-$ 218,318	$ 107,216
50	490	Computer Equipment	$ 581,101	$ 27,530		$ 608,631	-$ 506,535	-$ 44,282		-$ 550,817	$ 57,814
51	499	Contributions - Mains - Metallic (IGPC)	-$ 376,288	$ -		-$ 376,288	$ 41,750	$ 8,331		$ 50,081	-$ 326,207
51	499	Contributions - Mains Plastic	-$ 292,496	-$ 25,000		-$ 317,496	$ 19,184	$ 7,553		$ 26,736	-$ 290,760
51	499	Contributions - Services Metal	-$ 13,208	$ -		-$ 13,208	$ 2,279	$ 361		$ 2,641	-$ 10,567
51	499	Contributions - Services Plastic	-$ 457,030	-$ 47,250		-$ 504,280	$ 29,343	$ 10,847		$ 40,190	-$ 464,089
	401	Franchise & Consents	$ 842,667	$ -		$ 842,667	-$ 509,171	-$ 35,232		-$ 544,403	$ 298,264
	483	Furnishing / Office Equipment	$ 200,720	$ -		$ 200,720	-$ 122,766	-$ 7,774		-$ 130,540	$ 70,180
	480	Land	$ 82,653	$ -		$ 82,653	$ -	$ -		$ -	$ 82,653
51	475	Mains - Metallic	$ -	$ -		$ -	$ -	$ -		$ -	$ -
51	475	Mains - Metallic (IGPC)	$ 6,230,974	$ 300,000		$ 6,530,974	-$ 3,258,497	-$ 83,143		-$ 3,341,640	$ 3,189,333

51	475	Mains - Plastic	$ 16,153,236	$ 2,180,550		$ 18,333,786	-$ 7,028,203	-$ 332,082		-$ 7,360,285	$ 10,973,501
8	477	Measuring & Regulating Equip	$ 2,098,729	$ 342,430		$ 2,441,159	-$ 1,026,852	-$ 48,470		-$ 1,075,321	$ 1,365,838
8	477	Measuring & Regulating Equip (IGPC)	$ 576,367	$ -		$ 576,367	-$ 124,802	-$ 21,087		-$ 145,889	$ 430,478
51	478	Meters - Commercial	$ 1,926,249	$ 160,000		$ 2,086,249	-$ 1,054,324	-$ 82,072		-$ 1,136,396	$ 949,853
51	478	Meters - IGPC	$ 14,139	$ -		$ 14,139	-$ 14,139	$ -		-$ 14,139	$ -
51	478	Meters - Residential	$ 2,623,113	$ 824,640		$ 3,447,753	-$ 1,505,453	-$ 221,063		-$ 1,726,516	$ 1,721,237
8	474	Regulators	$ 807,746	$ 305,750		$ 1,113,496	-$ 447,083	-$ 29,501		-$ 476,584	$ 636,912
51	473	Services - Plastic	$ 6,614,832	$ 831,560		$ 7,446,392	-$ 3,148,256	-$ 102,590		-$ 3,250,846	$ 4,195,547
12	491	Software - Acquired	$ 748,287	$ 6,400		$ 754,687	-$ 542,247	-$ 42,592		-$ 584,839	$ 169,848
1	482	Structures & Improvements	$ 782,562	$ -		$ 782,562	-$ 340,147	-$ 12,333		-$ 352,480	$ 430,082
8	486	Tools and Work Equipment	$ 894,279	$ 23,400		$ 917,679	-$ 647,118	-$ 25,495		-$ 672,613	$ 245,065
10	485	Vehicle - Heavy Work Equip	$ 33,033	$ -		$ 33,033	-$ 11,918	-$ 2,335		-$ 14,253	$ 18,780
10	484	Vehicles - Transportation Equip	$ 771,093	$ 102,400		$ 873,493	-$ 458,205	-$ 84,810		-$ 543,015	$ 330,479
		Sub-Total	**$ 41,155,761**	**$ 5,044,940**	**$ -**	**$ 46,200,701**	**-$ 20,859,816**	**-$ 1,159,430**	**$ -**	**-$ 22,019,246**	**$ 24,181,455**
		***Less Other Non Rate-Regulated Utility Assets** (input as negative)*				$ -				$ -	$ -
		Total PP&E for Rate Base Purposes	**$ 41,155,761**	**$ 5,044,940**	**$ -**	**$ 46,200,701**	**-$ 20,859,816**	**-$ 1,159,430**	**$ -**	**-$ 22,019,246**	**$ 24,181,455**
		Construction Work In Progress	$ 188,447	-$ 188,447		-$ 0				$ -	-$ 0
		Total PP&E	**$ 41,344,209**	**$ 4,856,493**	**$ -**	**$ 46,200,701**	**-$ 20,859,816**	**-$ 1,159,430**	**$ -**	**-$ 22,019,246**	**$ 24,181,455**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total Net Depreciation						**-$ 1,159,430**			

Accounting Standard MIFRS
Year **2025 TEST**

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance [8]	Cost: Additions [4]	Cost: Disposals [6]	Cost: Closing Balance	Accumulated Depreciation / Contributions: Opening Balance [8]	Accumulated Depreciation / Contributions: Additions	Accumulated Depreciation / Contributions: Disposals [6]	Accumulated Depreciation / Contributions: Closing Balance	Net Book Value
50	488	Communication Equipment	$ 325,533	$ 17,525		$ 343,058	-$ 218,318	-$ 12,278		-$ 230,595	$ 112,463
50	490	Computer Equipment	$ 608,631	$ 57,525		$ 666,156	-$ 550,817	-$ 32,628		-$ 583,445	$ 82,711
51	499	Contributions - Mains - Metallic (IGPC)	-$ 376,288	$ -		-$ 376,288	$ 50,081	$ 8,331		$ 58,412	-$ 317,876
51	499	Contributions - Mains Plastic	-$ 317,496	-$ 25,000		-$ 342,496	$ 26,736	$ 8,131		$ 34,867	-$ 307,629
51	499	Contributions - Services Metal	-$ 13,208	$ -		-$ 13,208	$ 2,641	$ 361		$ 3,002	-$ 10,206
51	499	Contributions - Services Plastic	-$ 504,280	-$ 47,250		-$ 551,530	$ 40,190	$ 12,033		$ 52,224	-$ 499,306
	401	Franchise & Consents	$ 842,667	$ -		$ 842,667	-$ 544,403	-$ 35,232		-$ 579,635	$ 263,032
	483	Furnishing / Office Equipment	$ 200,720	$ -		$ 200,720	-$ 130,540	-$ 7,774		-$ 138,314	$ 62,406
	480	Land	$ 82,653	$ -		$ 82,653	$ -	$ -		$ -	$ 82,653
51	475	Mains - Metallic	$ -	$ -		$ -	$ -	$ -		$ -	$ -
51	475	Mains - Metallic (IGPC)	$ 6,530,974	$ 300,000		$ 6,830,974	-$ 3,341,640	-$ 89,084		-$ 3,430,724	$ 3,400,250
51	475	Mains - Plastic	$ 18,333,786	$ 1,381,350		$ 19,715,136	-$ 7,360,285	-$ 373,260		-$ 7,733,545	$ 11,981,591
8	477	Measuring & Regulating Equip	$ 2,441,159	$ 97,940		$ 2,539,099	-$ 1,075,321	-$ 56,525		-$ 1,131,847	$ 1,407,252
8	477	Measuring & Regulating Equip (IGPC)	$ 576,367	$ -		$ 576,367	-$ 145,889	-$ 21,087		-$ 166,976	$ 409,391
51	478	Meters - Commercial	$ 2,086,249	$ 157,000		$ 2,243,249	-$ 1,136,396	-$ 89,997		-$ 1,226,393	$ 1,016,857
51	478	Meters - IGPC	$ 14,139	$ -		$ 14,139	-$ 14,139	$ -		-$ 14,139	$ -
51	478	Meters - Residential	$ 3,447,753	$ 820,860		$ 4,268,613	-$ 1,726,516	-$ 293,693		-$ 2,020,208	$ 2,248,405
8	474	Regulators	$ 1,113,496	$ 255,740		$ 1,369,236	-$ 476,584	-$ 43,538		-$ 520,122	$ 849,114
51	473	Services - Plastic	$ 7,446,392	$ 816,160		$ 8,262,552	-$ 3,250,846	-$ 123,273		-$ 3,374,118	$ 4,888,434
12	491	Software - Acquired	$ 754,687	$ 10,000		$ 764,687	-$ 584,839	-$ 43,064		-$ 627,903	$ 136,784
1	482	Structures & Improvements	$ 782,562	$ 123,530		$ 906,092	-$ 352,480	-$ 13,518		-$ 365,998	$ 540,093
8	486	Tools and Work Equipment	$ 917,679	$ 23,030		$ 940,709	-$ 672,613	-$ 27,043		-$ 699,656	$ 241,052
10	485	Vehicle - Heavy Work Equip	$ 33,033	$ -		$ 33,033	-$ 14,253	-$ 2,335		-$ 16,588	$ 16,444
10	484	Vehicles - Transportation Equip	$ 873,493	$ 75,520		$ 949,013	-$ 543,015	-$ 85,328		-$ 628,343	$ 320,670
		Sub-Total	**$ 46,200,701**	**$ 4,063,930**	**$ -**	**$ 50,264,631**	**-$ 22,019,246**	**-$ 1,320,799**	**$ -**	**-$ 23,340,045**	**$ 26,924,586**
		***Less Other Non Rate-Regulated Utility Assets** (input as negative)*				$ -				$ -	$ -
		Total PP&E for Rate Base Purposes	**$ 46,200,701**	**$ 4,063,930**	**$ -**	**$ 50,264,631**	**-$ 22,019,246**	**-$ 1,320,799**	**$ -**	**-$ 23,340,045**	**$ 26,924,586**
		Construction Work In Progress	$ -	$ -		$ -				$ -	$ -
		Total PP&E	**$ 46,200,701**	**$ 4,063,930**	**$ -**	**$ 50,264,631**	**-$ 22,019,246**	**-$ 1,320,799**	**$ -**	**-$ 23,340,045**	**$ 26,924,586**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total Net Depreciation						**-$ 1,320,799**			

EPCOR Capitalization Policy - Financial

EPCOR Utilities Inc. Finance and Accounting Policy and Procedures			
Topic	**Capitalization**	Number	FA-004
Category	Property, Plant and Equipment Intangible Assets	Revision Number	5
Prepared by	Sarah Peng, Sr. Analyst, Consolidated Financial Reporting	Original issued and effective	September 23, 2004
Reviewed by	Parkash K. Motwani, Sr. Manager Consolidated Reporting and Analysis		
Approved by	Pamela Zrobek, Corporate Controller	Revision Issued and Effective	December 15, 2020

1. Purpose and Scope

1.1. The Capitalization Policy functions as a guide in respect of what should be recognized as a tangible asset or intangible asset other than goodwill. The intent is to ensure that the fixed assets are properly reported in the financial statements in accordance with International Financial Reporting Standards (IFRS).

1.2. This policy refers to capitalization of tangible assets and intangible assets other than goodwill..

2. Definitions and Background

2.1. **Asset** – a present economic resource controlled by the Company as a result of past events.

2.2. **Capital Asset Contributions** – are transfers from customers / developers of items of property, plant and equipment (PP&E) that must be used either to connect those customers to a network and / or to provide them with ongoing access to supply of goods or services.

Alternatively, cash contributions may be received from customers / developers or any other third party; or government grants may be received from federal, provincial or municipal governments for the acquisition or construction of such PP&E.

2.3. **Capitalized Borrowing Cost** – all finance charges that are directly attributable to the acquisition or construction of a qualifying asset, and recorded as part of the cost of that asset.

2.4. **Capital Spares** – major spare parts and stand-by equipment qualify as PP&E when the Company expects to use them during more than one period, or if the spare parts can be used only in connection with an item of PP&E they are capitalized.

2.5. **Capital Work-In-Progress (CWIP)** – Account(s) that include all costs of capital projects that are incomplete or not yet in service at the end of a reporting period.

2.6. **Cost** – the amount of cash or cash equivalents paid or the fair value of the other consideration given to acquire an asset at the time of its acquisition or construction or, where applicable, the amount attributed to that asset when initially recognized in accordance with the specific requirements of the IFRS.

PP&E

Cost of an asset being constructed includes contracted services, materials, direct labour, directly attributable overhead costs, borrowing costs on qualifying assets and decommissioning costs. Cost of an acquired asset includes its purchase price including import duties and non-refundable purchase taxes, any cost directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management and initial estimate of decommissioning costs. The cost of an asset may also include site preparation costs incurred to remove a previous asset when it is located at the site of the replacement asset.

Intangible asset

Cost of an acquired intangible asset includes purchase price including import duties and non-refundable purchase taxes, any directly attributable cost of preparing the asset for its intended use, payment of professional fees and cost of testing the asset to ensure the asset is functioning as intended. Cost of internally generated intangible asset includes cost of material and services used or consumed in generating intangible asset, employee benefits costs, fees to register legal rights, amortization of patents and licenses used to generate the intangible asset and overhead costs directly attributable to preparing the asset for use.

2.7. **Intangible Asset** – an identifiable non-monetary asset without physical substance.

2.8. **Property, Plant and Equipment (PP&E)** – tangible items that:

a) are held for use in the production or supply of goods or services, for rental to others, or for administrative purposes; and

b) are expected to be used during more than one period.

2.9. **Qualifying Asset** –an asset that necessarily takes a substantial period of time to get ready for its intended use or sale. For EPCOR, a qualifying asset is determined as a capital project that takes six months or more to construct or get ready for use.

2.10. **Right**-of-Use (ROU) Asset – Asset that represents the Company's right to use an underlying asset as a lessee for the lease term.

2.11. **Useful Life** is:

a) the period over which an asset is expected to be available for use by the Company; or

b) the number of production or similar units expected to be obtained from the asset by the Company.

The useful life is defined in terms of the asset's expected utility to the Company and is governed by physical and economic factors. For example, the end of an asset's physical life will generally be reached when the asset is no longer capable of performing its intended function because of physical wear. The end of the economic life of an asset is generally reached when a replacement asset is more economical to use than the current asset in place.

3. Capitalization Criteria

3.1. The cost of an item of PP&E or intangible asset should be recognized as an asset if, and only if:

a) It is probable that expected future economic benefits associated with the item will follow to the Company; and

b) The cost of the item can be measured reliably.

3.2. An expenditure that results in an asset with a useful life greater than one year should be capitalized.

3.3. An expenditure that results in extending the original life or useful life of an existing asset should be capitalized.

3.4. An expenditure that results in an increase in the previous assessed physical output or service capacity or efficiency of an existing asset should be capitalized.

3.5. An expenditure that results in reduction in the associated operating costs or improving the quality of output of existing asset should be capitalized.

3.6. An expenditure which is determined to be an asset under FA-005 - *Project Development Costs Policy* should be capitalized.

3.7. A cost incurred to ensure that an asset reaches its projected life (i.e. normal operations & maintenance) should not be capitalized and should be charged to net income as an expense in the period it is incurred.

3.8. The costs of the day-to-day servicing of the item of PP&E should not be capitalized and should be charged to net income as an expense in the period it is incurred. Costs of day-to-day servicing are primarily the costs of labour and consumables, and may include the cost of small parts. The purpose of these expenditures is often described as for the “repairs and maintenance” of the item of PP&E.

3.9. Related components purchased simultaneously with the intention of connecting them for use (e.g. computers) shall be capitalized as a single asset if the combined cost exceeds the capitalization dollar threshold. Unrelated projects should not be grouped together so as to meet or exceed the threshold outlined in Section 4.1.

3.10. Where parts of an item of PP&E have different estimated economic useful lives, they should be accounted for as separate items (major components) of PP&E

3.11. The cost of major inspections and maintenance should be recognized in the carrying amount of the item if the asset recognition criteria are satisfied. The carrying amount of a replaced part should be derecognized in accordance with the de-recognition policy.

4. Capitalization Threshold

4.1. All projects meeting the capitalization criteria in Section 3 should be capitalized if the cost exceeds $5,000.

4.2. All land has to be capitalized regardless of the amount.

4.3. For regulated businesses, certain assets may only be capitalized if they meet the specific criteria or listing approved by the regulator. Accordingly, under those circumstances, assets may be capitalized regardless of the amount.

5. Capital Spares

5.1. Spares and equipment, which meet the definition in Section 2.4 “Capital Spares” above and exceed the value of $5,000, should be capitalized.

6. Capital Work-in-Progress

6.1. The capital project balances in CWIP accounts should be transferred to PP&E when an asset moves into service. This occurs when an asset is available for use, i.e. when it is in the location and condition necessary for it to be capable of operating in the manner intended by management.

6.2. As noted in *FA-007 Depreciation and Amortization Policy* - paragraph 3.4, CWIP shall not be depreciated and shall be carried at cost less impairment, if any.

7. Capital Asset Contributions

7.1. Capital assets contributed by the customers or developers should be capitalized when the control of asset is transferred to the Company and they are available for use.

8. Capitalized Borrowing Cost

8.1. Borrowing cost that needs to be capitalized is calculated by each business unit (BUs) and added to the value of the asset in the CWIP accounts.

8.2. Borrowing cost to be capitalized is calculated for qualifying assets using the weighted average cost of debt incurred on EPCOR's external borrowing or specific borrowings used to finance qualifying asset. Borrowing cost to be capitalized should be calculated on a monthly basis by the respective BU

8.3. Capitalization of interest ceases when an item of PP&E is substantially complete and ready for productive use.

9. References

IFRS – The Conceptual Framework for Financial Reporting

IAS 16 – Property, Plant and Equipment

IAS 23 – Borrowing Costs

IAS 38 – Intangible Assets

10. Related Policies, Procedures and Guidelines

FA-005 – Project Development Costs Policy

FA-007 – Depreciation and Amortization Policy

EPCOR Capitalization Policy - Regulatory

EPCOR Regulatory Accounting Procedures			
Topic	**Capitalization for Regulatory Accounting Purposes**	Number	RA-004
Category	Property, Plant and Equipment Other Intangible Assets	Revision Number	3
Issued by	EDTI, EEAI, EWSI Finance	Issued and Effective	2011
Approved by	Pamela Chung Controller, EDTI Pat Bradley, Controller EEAI Lillian Zenari, Controller, EWSI	Revised	18-Oct-11

1. Purpose and Scope

The capitalization policy functions as a guide in respect of what should be recognized as a tangible asset or intangible asset other than goodwill for regulatory accounting and reporting. The intent is to ensure that fixed assets are properly reported in accordance with applicable regulatory accounting pronouncements.

This policy refers to capitalization of rate-regulated assets and intangible assets other than goodwill, primarily software. Related policies include Customer Acquisition Costs, Project Development Costs and Amortization and Depreciation.

2. Definitions and Background

Asset - "a resources controlled by the entity as a result of past events and from which future economic benefits are expected to flow to the entity"[1]

Property, Plant and Equipment (PPE) - " tangible items that: are held for use in the production or supply of goods and services, for rental to others, or for administrative purposes and; are expected to be used during more than one period"[2]

Rate-regulated property, plant and equipment - items of property, plant and equipment held for use in operations meeting all of the following criteria:

(a) the rates for regulated services or products provided to customers are established by or are subject to approval by a regulator or a governing body empowered by statute or contract to establish rates to be charged for services or products;

[1] Source: IFRS The Conceptual Framework for Financial Reporting. Chapter 4.4
[2] Source: IAS 16.6

(b) the regulated rates are designed to recover the cost of providing the services or products; and it is reasonable to assume that rates set at levels that will recover the cost can be charged to and collected from customers in view of the demand for services or products and the level of direct and indirect competition. This criterion requires consideration of expected changes in levels of demand or competition during the recovery period for any.

Allowance for Funds Used during Construction (AFUDC) – AFUDC is the amount that a rate-regulated enterprise may be allowed to earn, if approved by its regulator, to recover its cost of financing assets under construction. It is equal to the average cost of the capital-work-in-progress, times a financing rate, which is usually equal to the enterprise's cost of capital rate. AFUDC is included in the cost of the related assets and recovered in future periods through the depreciation charge.

Capital Asset Contributions - Contributions toward a capital asset owned by EPCOR which are received from an unrelated party or from another EPCOR entity, either in the form of cash or a non-monetary transfer of an asset. These contributions are recorded in a contra account as an offsetting credit to the related asset cost on the regulatory reporting balance sheet.

Capital Spares – major spare parts and stand-by equipment qualify as PP&E when an entity expects to use them during more than one period, or if the spare part can be used only in connection with an item of PP&E they are capitalized.

Cost – the amount of consideration given up to acquire, construct, develop, or better an item of property, plant and equipment. This incorporates all costs directly attributable to the acquisition, construction, development or betterment of the asset including installing it at the location and in the condition necessary for its intended use. For transmission, distribution and Regulated Rate Tariff PPE, the cost of the asset should include the costs to remove the previous asset, net of any salvage proceeds.

Capital Work-in-Progress (CWIP) – an account that includes all costs of capital projects that are incomplete or not yet in service at year-end. AFUDC is included in CWIP. Asset costs are accumulated in CWIP until the asset is put into service. When the asset is put into service its cost is transferred to PPE.

Property Unit Catalogue (PUC) – a list of rate-regulated assets with detailed definitions that have been approved by, or are in the process of being approved by, the regulator.

Useful life - "is:

(a) the period over which an asset is expected to be available for use by an entity; or

(b) the number of production or similar units expected to be obtained from the asset by the entity."[3]

The useful life can be either physical or economic. For example, the end of physical life will generally be reached when the asset is no longer capable of performing its intended function because of physical wear. The end of the economic life of an asset is generally reached when a replacement asset is more economical to use than the current asset in place.

[3] Source: IAS 16.6

Service Potential - "the output or service capacity of an item of property, plant and equipment and is normally determined by reference to attributes such as physical output capacity, associated operating costs, useful life and quality of output."[4]

3. General Capitalization Criteria

An expenditure should be capitalized if:

(a) It is identified as a rate-regulated asset in the PUC or

(b) It:

- (i.) results in a tangible asset with a useful life in excess of one year; and/or
- (ii.) extends the original life of an existing asset; and/or
- (iii.) enhances the service potential of an existing asset.

4. Capitalized Dollar Threshold

Land – no minimum value

In rate-regulated business units, there is no capitalized dollar threshold since an asset is capitalized if it is included in the PUC or if similar items with similar values have been approved by the regulator in current or prior rate applications.

[4] Source: CICA Handbook, Part II – Accounting Standards for Private Enterprises, Section 3061.03

5. Cost

The capitalized cost for regulatory purposes includes:

(a) The cash or cash equivalents paid or fair value of the other consideration given to acquire an asset at the time of its acquisition or construction,

(b) Site preparation costs incurred to remove a previous asset when it is located at the site of the replacement asset

(c) Capital overhead

(d) AFUDC

6. Capital Spares

In rate-regulated business units a component is considered to be a capital spare if it is approved by the regulator.

7. Allowance for Funds Used During Construction (AFUDC)

AFUDC reflects the carrying costs attributable to funds expended for capital projects. AFUDC is determined based on a financing rate equivalent to the business unit's weighted average cost of capital rate (as approved by the regulator) applied to the mid year CWIP balance.

AFUDC is added to the cost of the asset and recovered in future periods through the depreciation charge.

8. Capital Asset Contributions

Capital asset contributions are recorded in the regulatory accounts as a “credit contra account” included in the determination of PPE. The amounts are subsequently amortized by a charge to accumulated depreciation and a credit to depreciation expense, calculated using the same life span as that used for the amortization of the related property, plant and equipment asset.

9. References

IFRS – Framework
IFRS - IAS 16 – Property, Plant and Equipment
CICA Handbook, Part II – Accounting Standards for Private Enterprises, Section 3061

10. Related Policies, Procedures and Guidelines

EPCOR’s Amortization and Depreciation Policy RA-007
Property Unit Catalogues (as applicable)
AUC Rule 026

EPCOR Capital Overhead Policy

EPCOR Utilities Inc. Finance and Accounting Policy and Procedures			
Topic	**Capital Overhead**	Number	FA-010
Category	Property, Plant and Equipment & Intangible Assets	Revision Number	2
Revised by	Sarah Peng, Sr. Analyst, Financial Reporting	Original Issued and Effective	December 31, 2006
Issued by	Parkash K. Motwani, Senior Manager Consolidated Reporting and Analysis		
Approved by	Jacyn Koski, Corporate Controller	Revision Issued and Effective	December 15, 2020

1. Purpose and Scope

1.1. The purpose of this policy is to identify the types of overhead costs that can be capitalized in the course of acquiring or constructing an item of property, plant and equipment (PP&E) or intangible asset in accordance with International Financial Reporting Standards (IFRS).

1.2. This policy should be applied consistently by all EPCOR entities.

2. Definitions and Background

2.1. **Cost** - the amount of cash or cash equivalent paid or the fair value of other consideration given to acquire an asset at the time of its acquisition or construction or, where applicable, the amount attributed to that asset when initially recognized in accordance with the specific requirements of the IFRS.

PP&E

Cost of asset being constructed includes contracted services, materials, direct labour, directly attributable overhead costs, borrowing costs on qualifying assets and decommissioning costs. Cost of acquired asset includes purchase price including import duties and non-refundable purchase taxes, any cost directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management and initial estimate of decommissioning costs. The cost of an asset may also include site preparation costs incurred to remove a previous asset when it is located at the site of the replacement asset.

Intangible asset

Cost of acquired intangible asset includes purchase price including import duties and no-refundable purchase taxes, any directly attributable cost of preparing the asset for its intended use, payment of professional fees and cost of testing the asset to ensure the asset is functioning as intended. Cost of internally generated intangible asset includes cost of material and services used or consumed in generating intangible asset, employee benefits costs, fees to register legal rights, amortization of patents and licenses used to generate the intangible asset and overhead costs directly attributable to preparing the asset for use.

2.2. **Overhead costs** – includes labour and salary related costs of support functions such as executive oversight, corporate accounting, legal, human resources, information systems, marketing, purchasing and office management.

2.3. **Directly attributable costs** – those costs that directly relate to the acquisition or construction of PP&E or intangible asset. If the activity to acquire or construct PP&E or intangible asset did not occur, directly attributable costs would not have been incurred.

Examples of directly attributable costs are:

- costs of employee benefits arising directly from the employees involved in the construction or acquisition of the item of PP&E or intangible asset;
- costs of site preparation;
- initial delivery and handling costs;
- installation and assembly costs;
- costs of testing whether the asset is functioning properly; and
- professional fees

2.4. **Capital Overhead Allocation Pool (the pool) –** the accumulation of overhead costs that are directly attributable to the acquisition or construction of PP&E or intangible asset.

3. Policy

3.1. Only overhead costs that are directly attributable to the acquisition or construction of PP&E or intangible asset should be capitalized as per FA-004 - *Capitalization Policy* and FA-005 - *Project Development Costs Policy*. Labour (including incentive pay) and labour-related expenses such as employee benefits and overtime, which are directly attributable to the capital expenditures based on either time spent or headcount, are the only overhead costs that should be capitalized.

3.2. Overhead costs identified for capitalization should be pooled prior to being allocated to individual capital projects. Pools of overhead costs should be separately identified for individual business units' (BUs) or specific major projects, as necessary. An estimate of capital overhead costs to be contributed to the pool should be based on the budget at the beginning of each year.

3.3. Each identified overhead cost in the pool should be documented and a justification should be provided as to how it is directly attributable to the capital projects to which it is being allocated. The BU Controller should approve the components of the pool to ensure that each element is directly attributable to the acquisition or construction of that PP&E or intangible asset.

3.4. The capital overhead rate (the rate) is calculated by dividing the pool by the total direct regular labour capital expenditures for the year. This rate is then applied to all major capital labour expenditures incurred during the year. A different rate may be calculated for a specific project, if overhead costs can be separately identified for that project. The rationale for having a different rate should be documented and approved by the BU Controller.

3.5. BUs shall prepare a reconciliation of the rate on a regular basis by comparing the pool of costs (numerator) and the total forecast capital labour expenditures (denominator). If the reconciliation indicates that a change to the rate is required, the rate change shall be applied on a prospective basis only. If required, a manual adjustment shall be booked to clear any significant difference between the pool and the recovery. The rate reconciliation, changes to the rate and any manual adjustments must be reviewed and approved by the BU Controller.

3.6. By the end of each fiscal year, the overhead costs that have been allocated to the pool based on budget during the year should be compared to the actual overhead costs incurred and any material differences should be booked to the pool. At year-end, any material balance remaining in the pool should be fully allocated to the actual capital projects completed or in progress during the year. The annual reconciliation of the pool should be reviewed and approved by the BU Controller.

3.7. Certain of the Corporate Shared Services groups may have costs, which are directly attributable to capital activities. These costs should be assigned/directly charged to the pools.

4. Documentation

4.1. Each BU should document the method by which they are allocating their capital overhead, including a justification of how each overhead cost is directly attributable to the capital expenditures. This documentation should be approved by the BU Controller.

4.2. Any changes to the rate during the year should be documented and approved by the BU Controller.

4.3. Documentation of the annual true-up of the pool should also be approved by the BU Controller.

4.4. All documentation should be maintained by the BUs and be available for review by Corporate Finance, internal auditors, or external auditors, as required.

5. References

IAS 16 – Property, Plant and Equipment

IAS 38 – Intangible Assets

6. Related Policies, Procedures and Guidelines

FA-004 – Capitalization Policy

FA-005 – Project Development Costs Policy

EPCOR Burden Procedure and Policy

EPCOR Utilities Inc. Finance and Accounting Policy and Procedures			
Topic	**Standard Rates and Burden Rates for Project and Activity Costing**	Number	FA-011
Category	Property Plant & Equipment, Intangible Assets and Operating Expenses	Revision Number	2
Revised by	Sarah Peng, Sr. Consolidated Financial Reporting	Original Issued and Effective	January 1, 2008
Reviewed by	Parkash K. Motwani, Senior Manager Consolidated Reporting and Analysis		
Approved by	Pamela Zrobek, Corporate Controller	Revision Issued and Effective	December 15, 2020

1. Purpose and Scope

1.1. The Standard Rates and Burden Rates policy provides guidance on how to measure the cost of employee time spent on and transferred to capital projects or operating activities outside the employee's home department for preparing general-purpose financial statements in accordance with International Financial Reporting Standards (IFRS). Capital projects may relate to items of property, plant & equipment (PP&E) or intangible assets.

1.2. This policy should be applied consistently by all EPCOR entities, with the exception of EPCOR USA entities which calculate their separate rates and any entities governed by management agreements (e.g. joint ventures) to the extent they have specific contractual criteria governing standard rates and overheads costing which are not consistent with this policy.

2. Definitions and Background

2.1. **Burden rate** – is a rate or series of rates representing specific Overhead Costs applicable to measuring the cost of capital or operating activities.

2.2. **Directly attributable costs** – includes costs directly attributable to an operating activity or to the acquisition or construction of PP&E or intangible asset to bring an asset to the location and condition necessary for it to be capable of operating in the manner intended by management. If the activity did not occur, directly attributable costs would not have been incurred.

An example of a directly attributable cost is the cost of employee benefits arising directly from employee's service in performing the operating activity or in the acquisition or construction of an item of PP&E or intangible asset.

2.3. **Employee benefits** – are all forms of consideration given by an entity in exchange for services rendered by employees or for the termination of employment.

2.4. **In-scope employees** – employees who perform jobs which participate in a union pursuant to a collective bargaining agreement with EPCOR.

2.5. **Other long-term employee benefits** - are all employee benefits other than short-term employee benefits, post-employment benefits and termination benefits.

Example includes long-term disability plan.

2.6. **Overhead costs –** includes salary and salary related costs of support functions such as executive oversight, corporate accounting, legal, human resources, information systems, marketing, purchasing and office management.

2.7. **Post-employment benefits** – are employee benefits (other than termination benefits and short-term employee benefits) that are payable after the completion of employment.

Examples include defined contribution pension plans (e.g. Local Authorities Pension Plan or LAPP) and defined benefit pension plans.

2.8. **Rate-ups** – Incremental increases of in-scope employees' hourly rates based on temporarily performing higher-paying job duties compared with those in which they are currently employed, pursuant to a collective bargaining agreement.

2.9. **Shift differentials** – Incremental rate premiums paid to in-scope employees for hours worked during premium rate shift hours, pursuant to a collective bargain agreement.

2.10. **Short-term employee benefits** – are employee benefits (other than termination benefits) that are expected to be settled wholly before twelve months after the end of annual reporting period in which the employees render the related service.

Examples include but are not limited to medical and dental plan benefits, Canada Pension Plan (CPP) and Employment Insurance (EI) benefits, worker's compensation insurance, short-term compensated absences such as paid annual vacation, bonuses and other profit-sharing such as the EPCOR Savings Plan for non-bargaining unit staff.

2.11. **Standard rate** – the hourly wage rate established for a job within EPCOR, based on the criteria described in Section 4 below, for purposes of costing employee time spent on capital or operating projects or activities.

2.12. **Termination benefits** – are employee benefits provided in exchange for the termination of an employee's employment as a result of either:

a) an entity's decision to terminate an employee's employment before normal retirement date; or

b) an employee's decision to accept an offer of benefits in exchange for the termination of employment.

3. Policy

3.1. The cost of employees' time is included in the cost of an operating or capital activity based on the actual hours for which each employee's time is directly attributable to the activity, measured by applying the hourly standard rate determined in Section 4 below. The offsetting recovery or credit of time charged to an activity is reflected in the general ledger in the same Oracle responsibility centre where the original salary and wage cost for the employee was recorded (i.e. the employee's home account).

3.2. Burden rates established by this policy to measure directly attributable overhead costs are reflected in the cost of an operating or capital activity with the credit or recovery reflected in such a manner as to offset the actual related costs. Section 4 of this policy provides specific guidelines on which overhead costs may be included in the burden rates.

3.3. The standard rates and burden rates established in accordance with this policy should be updated annually, or more frequently if events occur which indicate a revision is required. This update should be performed in accordance with Section 5 described below.

3.4. Standard rates and burden rates should be reviewed for reasonability in comparison to actual pay rates and applicable overhead costs (e.g. fringe benefits) at least annually or more frequently when there are indications that the standard or burden rates are significantly under-recovering or over-recovering the cost of employee time and related benefits and overheads. This review should be performed in accordance with Section 7 described below.

4. Components of Standard Rates and Related Overheads

4.1. Standard rates for regular time are comprised of a reasonable proxy of the hourly pay rate for in-scope employee positions based on the highest step rate as disclosed in the collective bargaining agreements, and an average of actual hourly compensation for out-of-scope hourly employees. See **Appendix A** for specific guidelines on standard rate calculations.

4.2. Overtime rates are calculated by applying a multiplier (i.e. two times or 2x and in some case one and half times or 1.5x) to the standard hourly rate for in-scope employees and specifically exclude management/out-of-scope employees not specifically compensated for overtime hours. See **Appendix A** for specific guidelines on overtime rate calculations.

4.3. Overheads or burdens applied to standard rates are comprised of:

4.3.1. Employee benefits – a standard percentage rate should be established for organizations within EPCOR (excluding U.S. operations which calculates a separate rate for employees based in U.S.) that reasonably represents the employer's share of employee benefit costs relating to both short-term benefit costs, post-employment benefit costs and other long-term benefit costs.

4.3.2. Paid annual vacation benefits, family leaves, statutory holidays, management's scheduled days off and personal leave days will be included in burden rates for project costing. Although most of these paid days off are non-accumulating absences (do not carry forward), they are not coded to the project and therefore must be included in the burden rate to recognize the true project cost. Since these costs all relate to the time spent on the project, they are considered to be a directly attributable cost of the project.

4.3.3. A reasonable estimate of the impacts of rate-ups and shift differentials for certain in-scope positions based on historical information and the current collective bargaining agreement.

4.3.4. Employee incentive – variable incentive pay meets the definition of an overhead cost or burden under this policy. However, it is EPCOR's practice to include incentive pay allocated to capital work activity through its capital overhead rates - see FA-010 - *Capital Overhead Policy* for details. As a result, the employee incentive is not included in the burden rate calculations referred to in Section 4.3.5 below to avoid duplication with capital overhead rates.

Operating activity salary transfers between legal entities are not material to warrant a separate burden rate for incentive pay on operating salary transfers.

4.3.5. Refer to **Appendix B** for guidelines for calculating burden rates.

4.4. The following are specifically prohibited from inclusion in overheads and burdens applied to standard rates:

4.4.1. Termination benefits paid to former employees.

4.4.2. Costs of opening a new facility.

4.4.3. Costs of introducing a new product or service (including costs of advertising and promotional activities).

4.4.4. Costs of conducting business in a new location or with a new class of customer (including costs of staff training).

4.4.5. Administration and other general overhead costs (excluding directly attributable overhead costs).

5. Revisions to Standard Rates and Burden Rates

5.1. Standard rates should be revised by the Human Resources (HR) group at least annually, as follows:

5.1.1. At the beginning of a fiscal year to reflect increments in collective bargaining agreements for in-scope employee positions and to reflect estimated cost of living adjustments for management or out-of-scope employee positions;

5.1.2. At the time of effective approval of a revised collective bargaining agreement for in-scope employee positions, or a change in pay bands for management or out-of-scope employee positions;

5.1.3. At the time of introduction of a new in-scope employee position or management or out-of-scope employee pay band; and/or

5.1.4. When the regular monitoring of reasonability of standard rates (see Section 7 below) gives rise to a need for adjustment of the standard rates.

5.2. Burden rates shall be reviewed for reasonability in comparison to actual fringe benefit and other applicable overhead costs at least annually, as part of the budgeting process. See Section 7.1 below.

5.3. Retroactive adjustments to standard rates and burden rates – standard and burden rates are used to approximate the cost of labour and related overheads using standard (not actual) rates. In general, there should not be retroactive adjustments to the rates applied to previously charged operating and capital activities or projects unless the lack of adjustment results in material misstatement of a legal entity's results.

6. Responsibility for Determination and Approval of Standard and Burden Rates

6.1. Standard rates should be calculated for use across EPCOR (excluding U.S. operations which calculates a separate rates for employees based in U.S.) rather than being BU specific. The calculations should be performed centrally by the HR group, with:

(1) appropriate knowledge of this policy and related accounting standards; and

(2) the skills necessary to perform the calculations.

6.2. Generally, burden rates should be calculated for use across EPCOR's BUs (excluding U.S. operations which calculates a separate rate for employees based in U.S.). However, where there are unique BU-specific burden types or rates which are determined to be necessary to appropriately reflect costs of operating or capital activities in accordance with IFRS, consideration may be given to application of BU-specific burden types and rates. For example, fringe benefit or vacation costs if they vary significantly by BU may justify the establishment of unique rates to meet individual legal entity reporting requirements.

6.3. The standard and burden rates should be reviewed and approved by a senior financial manager with the appropriate knowledge and skills to perform the review.

7. Monitoring Reasonability of Standard Rates and Burden Rates

7.1. Since the setting of standard rates and burden rates relies on estimates and averages of actual pay rates and actual related overhead costs such as fringe benefits, there is the possibility of over-recovery or under-recovery of actual costs. The Corporate Accounting group should coordinate at least an annual review of salary and burden recoveries compared to actual costs at a legal entity level. The recommended time period for the annual review is the second quarter to allow sufficient time for adjustment to rates, prior to year-end.

7.2. The analysis and conclusion as to the reasonability of the rates will either directly involve a BU Controller or their designate, or there should be communication to each BU Controller on the results for their consideration and agreement. If the rates are determined to result in material error, action should be taken to adjust them pursuant to Sections 5 and 6 above.

7.3. The reasonability review should take into consideration the materiality levels of the individual legal entity if they involve external reporting requirements and materiality levels for EPCOR on a consolidated basis.

8. References

IAS 16 – Property, Plant and Equipment

IAS 19 – Employee Benefits

IAS 38 – Intangible Assets

9. Related EPCOR Policies, Procedures and Guidelines

FA-004 – Capitalization Policy

FA-010 – Capital Overhead Policy

Appendix A: Procedures/Guidelines for Calculation of Standard Rates

The following are guidelines used by HR for calculating standard rates for regular time:

In-scope hourly employees

For each job (also commonly referred to as "job grade" or "job title") identified in a collective bargaining agreement, use the top tier or highest step hourly pay rate as the standard rate for that job. For simplicity, rates should be rounded to the nearest dollar.

Out-of-scope hourly employees

For out-of-scope hourly (OSH) employees, use the top tier or highest step. If there are material differences in wages between regions or provinces, separate standard rates will be created for each site. OSH employees are not party to a formal collective bargaining agreement because they relate to employees outside of Edmonton who joined EPCOR through acquisition of an operation. In the absence of this information, an average of the previous year's hourly wage indexed to inflation, as per the Bank of Canada, should be substituted as the top tier pay-step. For simplicity, rates should be rounded to the nearest dollar.

Management and other non-hourly out-of-scope employees

For management and other non-hourly out-of-scope employees, the average hourly pay rate for each pay band is determined as follows:

- The annual compensation "target" for each pay band is used to establish the standard rate for all positions administered in the pay band. As a result, the same standard rate is used across all BUs and on an individual BU basis.

Appendix A: Procedures/Guidelines for Calculation of Standard Rates (continued)

The following procedures shall be applied for calculating Standard Rates for overtime:

- Overtime rates are calculated by applying the same multiplier used for the overtime rate (i.e. 2x or 1.5x) to the standard hourly rate for **in-scope employees and out-of-scope hourly employees** to reflect "double-time" rates pursuant to a collective bargaining or other agreements.
- A multiplier of zero is applied to overtime hours reported by **management and other out-of-scope non-hourly employees**. This means that management staff is not specifically compensated for overtime (paid on annual salary basis).

The above procedures/guidelines may be amended as long as they conform to the general policy requirements outlined in Section 4 of this policy document.

Appendix B: Procedures/Guidelines for Calculation of Burden Rates

The following suggested procedures and guidelines may be applied for calculating burden rates applied to salary and labour transfers in the general ledger.

Employee benefits:

A rate may be calculated for EPCOR based on forecasted or actual total costs of the following examples of employee benefits as a proportion of total forecasted or actual salary and wage costs for Canadian operations:

- Medical and dental plans
- CPP and EI benefits
- Pension benefits (LAPP, RCPP, OMERS, and other pensions)
- Health care including long-term disability
- Worker's compensation
- EPCOR Savings Plan for non-bargaining unit staff
- Shepell costs related to the Employee Assistance Program
- Sunlife administrative fees
- Wellness plan

Information related to the costs of these benefits will be available from HR and/or related payroll systems.

Vacation benefits:

Vacation benefits rates may be calculated by obtaining information from HR on average vacation entitlements across EPCOR as a proportion of total working days. For example, if the average vacation entitlement was approximately 19 days and total working days were 261, vacation benefit rate would be approximately 7%.

Statutory Holidays, Management Scheduled Days Off, Family Leave and Personal Leave Entitlement:

Statutory holidays, management scheduled days off, family leave and personal leave benefit rates may be calculated by obtaining workforce information from HR and calculating average entitlements across EPCOR as a proportion of total working days. Since entitlement varies based on employee status, a weighted average entitlement is calculated to reflect average days off for the entire EPCOR workforce for each type of paid day off. The weighted average number of days off is then calculated as a percentage of total working days in the year.

Rate-ups/Shift-differentials:

A rate may be calculated with respect to rate-ups and shift differentials by obtaining historical information on the cost of these pay adjustments as a proportion of total base salary & labour costs.

The above procedures/guidelines may be amended as long as they conform to the general policy requirements outlined in Section 4 of this policy document.

ENGLP - Utility System Plan & Asset Management Plan

ENGLP Natural Gas Limited Partnership (Aylmer)

2025 – 2029 Utility System Plan

Table of Contents

1.0 Utility System Plan Overview

ENGLP Natural Gas Limited Partnership's (ENGLP) Utility System Plan (USP) documents ENGLP's asset management processes and capital expenditure plan for the 2025-2029 period. The USP provides interested stakeholders with the information required to determine if a utility is meeting the objectives outlined under the Ontario Energy Board's (OEB) Renewed Regulatory Framework (RRF).

The Utility System Plan documents the practices, policies and processes that are in-place to ensure that investment decisions support ENGLP's desired outcomes in a cost-effective manner and provides value to the customer. ENGLP's Utility System Plan is designed to support the achievement of the four key OEB established performance outcomes:

1) **Customer Focus:** services are provided in a manner that responds to identified customer preferences;
2) **Operational Effectiveness:** continuous improvement in productivity and cost performance is achieved, and utilities deliver on system reliability and quality objectives;
3) **Public Policy Responsiveness:** utilities deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board); and
4) **Financial Performance:** financial viability is maintained, and savings from operational effectiveness are sustainable.

The natural gas distribution system is capital intensive in nature and prudent capital investments and maintenance plans are essential to ensure the sustainability of the distribution network. As part of its planning process, ENGLP has aimed for a consistent capital budget envelope for the USP period that balances annual mandatory investments with non-mandatory through a project pacing and prioritization process. Individual capital investment category variation recognizes the specific impact of System Access work on the ability of ENGLP to do other work at the same time while keeping rates manageable. Similarly, non-mandatory work is prioritized, paced and managed to provide consistent yearly overall capital spends. While individual capital categories may vary from year to year, ENGLP's overall Capital spend has been kept relatively consistent over the USP plan period to provide a steady and predictable impact on rates.

2.0 Investment Planning Process

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 and Utility System Plans.

ENGLP's Utility System Plan 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 mandatory investments with non-mandatory needs 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
- 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 trigger 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, modification 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.

The breakdown of the investment categories has been summarized in Table 1 below:

Table 1: Investment Categories

USP Category	Asset Program
System Access	Main Additions - Steel (Distribution Plant) Main Additions - Plastic (Distribution Plant) Service Additions – Plastic Meter Additions Regulator Additions Industrial/Commercial Large Load Relocations
System Renewal	Main Replacements Service Replacements Regulating Station Upgrade and Maintenance Meter Replacements Regulator Replacements IGPC 6inch Steel Pipeline Asset Management
System Service	Integrity SCADA System Reinforcements

General Plant	Fleet Vehicles IT Hardware, OT Cyber security and Mobile Apps Small Tools and Work Equipment Land/Building Improvements

3.0 Overview of 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 along with reliability remain top concerns. Satisfaction with ENGLP remains high despite perceptions of high energy costs. As costs rise, so too expectations from customers. 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.

In response to customer feedback, ENGLP has aimed for a consistent capital budget envelope for the USP period that balances mandatory investments with non-mandatory needs through a project pacing and prioritization process. ENGLP has developed a prudent five year capital investment and maintenance plan to ensure the reliability and sustainability of its distribution network. The capital spend profile supports customer growth and asset integrity replacements that will support the addition of new customers, as well as maintain existing assets in a safe and reliable manner.

The results of the customer engagement survey completed by Stone Olafson are attached at the end of this document

4.0 Capital Program Planning

ENGLP completes an annual budget and conducts a multi-year planning process that includes forecast of volumes, revenues, capital investments and operating and maintenance costs. The budgeting process allows ENGLP to execute on its strategic priorities and ensures safe and reliable operations are maintained. Further, for every rate application, ENGLP develops and publishes its 5-year capital program, presented through the USP. The capital program planning element has five steps.

4.1.1 Element 1: Project Creation

The first step is the creation of proposed capital projects. ENGLP accomplishes this a few ways. One method is by layering the asset condition information into the GIS. Using a GIS layer to do this allows for a visualization of where there may be a grouping of poor assets such as gas mains in need of replacement. Another method is through the review of asset condition or inventory information to identify potential projects such as station upgrades or replacements. At this stage, a review of non-distribution alternatives would be considered for any new system service or access projects.

Information Technology (IT) or Operational Technology (OT) Projects are proposed following a needs assessment review. This is a review of existing IT/OT software and hardware vendor upgrades or refreshes, network maintenance criteria, cyber security requirements and also a scan of emerging technologies considering customer preferences and feedback.

4.1.2 Element 2: Project Risk Assessment and Ranking

This critical step of the Capital Program Planning cycle requires a structured approach to ensure an optimal and efficient capital investment program that is supported by empirical evidence. This is most important when reviewing non-mandatory System Renewal, System Service and General Plant projects given there are typically more potential projects than can be accomplished with resources and funding. Each project is run through a consistent risk ranking exercise against some key asset management objectives.

ENGLP has identified six (6) Asset Management Objectives:

- Safety - Construct, maintain and operate all assets in a safe manner;
- Reliability - Monitor and address asset condition issues in a timely manner to ensure the continued reliable supply of natural gas delivery;
- Customer Service - Ensure corporate performance and asset management plans align with customer service expectations;
- Financial Integrity - Manage investment planning to mitigate rate impacts while maintaining corporate financial stability and long-term sustainable performance;
- Effective Integration - Develop and improve the GIS as the prime asset management register;
- Environmental - Ensure that environmental considerations are taken into account in the design and management of the distribution system.

The Asset Management objectives form the high-level philosophy framework for ENGLP's investment program and are implicitly embedded in ENGLP's capital investment planning process and maintenance program.

For investment benefit and risk assessment, it is necessary to identify the relative priority of each asset management objective with respect to each other. Different investments will have different benefits and risks with respect to the asset management objectives and weighting the asset management objectives will aid in identifying those investments that best align with them from an overall benefit and risk perspective. The six objectives are each assigned a relative weight of 0 - 1.0 with the total sum of the objectives equalling 1.0.

Safety – This objective has been given the highest priority by ENGLP. Safety comprises organizational efforts to ensure that worker and public safety is paramount in day to day activities.

No other objective is weighted higher than safety. The Safety objective is assigned a weight of 0.30.

Reliability – This objective is the second highest priority. Together with safety it is a key corporate objective outcome. In customer surveys, it has ranked high in importance of customer needs. The Reliability objective is assigned a weight of 0.20.

Customer Service – This objective ranks relatively high in ensuring that business outcomes meet the value needs of the customer. The customer objective is assigned a weight of 0.20.

Financial integrity - A stable rate of return, low distribution rates and the ability to sustainably invest in distribution system access, service, renewal and general plant are key to the long term success of this objective. Balancing of stakeholder interests in this area is an ongoing exercise. In customer surveys, low natural gas rates ranked high in importance of customer needs. The financial integrity objective is assigned a weight of 0.15.

Effective integration – This objective ensures that continual improvement of processes and practices ranks high in consideration of program development and deliverables. It is assigned a weight of 0.10.

Environmental – It is recognized that environmental considerations benefit the community as a whole. The Environmental objective is assigned a weight of 0.05.

Table 2 – Objective Weighting Summary

Objective	Weight
Safety	0.30
Reliability	0.20
Customer Service	0.20
Financial Integrity	0.15
Effective Integration	0.10
Environmental	0.05
Total	1.00

ENGLP uses a Risk and Value scoring mechanism developed internally to classify and prioritize investments against these Asset Management objectives. Risk and Value assessments provide an initial triage to determine projects that can wait (be deferred to future budget periods) and those that need closer review for potential inclusion in the immediate planning period.

IT/OT projects (General Plant and System Service) follow a modified risk ranking exercise looking at the same Asset Management objectives (Strategic/Customer Alignment) adding weight scores for benefits and subtracting weight scores for the risks introduced through implementation.

Attached below is a summary of each capital program and project contemplated in the current USP period that is through the risk ranking exercise against key asset management objectives.

ENGLP USP Risk Ranking Matrix_2025

4.1.3 Element 3 and 4: Project Selection and Estimating

During these steps, the ranking of projects aids in the selection of projects that should move to the next phase project estimating. This becomes an above the line, below the line iterative exercise with the risk assessment step given shifting business priorities, customer feedback, and policy direction. Preliminary Project estimates are built based on historical spend and vendor quotes.

The step also includes the inclusion and impact of the mandatory projects. Mandatory capital projects are automatically included as per scheduled need. In general, mandatory projects are defined as:

- Additions and Modifications including asset relocation to the distribution system (System Access)
- Mandated service obligations (System Access)
- Safety and Reliability related projects (System Service)

4.1.4 Element 5: USP and Annual Budget Planning

The outcome of the Capital Program Planning element is the five year capital program or Utility System Plan and the annual capital budget. Capital Investments in a capital program are placed in one of the four investment categories: System Access, System Renewal, System Service or General Plant. This outcome is a result of the iterative steps of project risk assessment, selection and estimating. Mandatory investments are allocated budget envelope funds first and the remainder allocated to non-mandatory investments.

The intent is for the annual budget to reflect the USP as closely as possible, however, there is opportunity for projects to move around or new projects to be introduced due to changing conditions or customer needs. The intention of this prioritization is to remain within the USP capital spend profile for the categories of system renewal, system access, system service and general plant. Customer connection enhancements beyond this would be subject to ENGLP's connection policies and require a profitability index calculation. Material changes could result in an incremental capital model submission to the OEB.

Capital budgets are prepared and submitted by management in Q1 of the preceding year (e.g. 2025 budget submitted in Q1 2024). They are reviewed and approved by the senior management including the Controller, Vice President Ontario Region and the accountable Senior Vice President – in Q2 and, finally, the Boards of Directors in Q4.

4.1.5 Step 5: Capital Project Delivery

ENGLP follows EPCOR's organizational project management process to deliver capital projects. Prior to finalizing the annual budget or approving any spend, a project justification is completed. This is a focused review of the risk assessment and cost benefit analysis of the project. This requires approval by ENGLP's Executive Management Team including the Senior Vice President. This is followed by Project Design where a more detailed estimate, technical design and schedule are developed. Project execution is tracked against the budget and schedule. Finally, the project is financially closed out following required accounting principles.

5.0 ENGLP Capital Expenditure Plan (2025-2029)

ENGLP's Utility System Plan details the program of system investment decisions developed on the basis of information derived from ENGLP's engineering plan, asset management plan, customer input and capital expenditure planning process. Investments, whether identified by category or by specific project, are justified in whole or in part by reference to specific aspects of the above three processes.

ENGLP's Utility System Plan includes information on prospective investments over a five year forward looking period (2025 – 2029) as well as planned and actual information on investments over the historical five year period (2020 – 2024).

ENGLP expects moderate load and customer growth in line with development plans that directly impact ENGLP's service territory. System Access investments will provide for new customer connections over the period of the USP. System Renewal investments (condition based replacement) will ensure that customer service levels with respect to safety and reliability are maintained. Inspection and performance analytics help direct preventive maintenance to specific at-Risk equipment and extend further the safe reliable useful life of all equipment.

Individual capital investment category variation recognizes the specific impact of System Access work and other competing needs on the ability of ENGLP to fund/complete other work at the same time, while remaining within the approved rate structure. Other non-mandatory work (i.e. System Renewal, System Service and General Plant) is prioritized, paced and managed to provide consistent yearly overall capital spends. While individual capital categories may vary from year to year, ENGLP's overall Capital spend has been kept relatively consistent over the USP plan period to provide a steady and predictable impact on rates.

The following table summarizes the planned capital expenditures (annual $ and % spend), by investment category, for the period 2025 through 2029:

Table 3: ENGLP Planned Capital Expenditures (Annual $ and % Spend) – 2025-2029

	Investment Category	A 2025 Test Year	B 2026 F 2	C 2022 F 3	D 2028 F 4	E 2029 F 5
1	System Access	1,855,650	2,257,465	1,593,180	1,675,060	1,750,610
2	System Renewal	1,456,150	1,563,620	908,520	926,190	563,290
3	System Service	450,050	39,950	405,030	408,540	50,050
4	General Plant	272,080	152,000	159,600	164,020	168,400
5	**Total**	**4,063,930**	**4,013,035**	**3,066,330**	**3,173,810**	**2,532,350**
	Investment Category	**A 2025 Test Year**	**B 2026 F 2**	**C 2022 F 3**	**D 2028 F 4**	**E 2029 F 5**
1	System Access	46%	56%	52%	53%	69%
2	System Renewal	36%	39%	30%	29%	22%
3	System Service	11%	1%	13%	13%	2%
4	General Plant	7%	4%	5%	5%	7%
5	**Total**	**100%**	**100%**	**100%**	**100%**	**100%**

ENGLP's projected annual spend ranges between $2.5 million to $4.0 million from 2025 to 2029. System Access is ENGLP's highest asset investment category ranging between $1.5 million to $1.9 million while System Renewal is the second highest asset investment category ranging between $500,000 to $1.5 million from 2025 to 2029. The capital spend profile supports customer growth and asset integrity replacements that will support the addition of new customers, as well as maintain existing assets in a safe and reliable manner.

6.0 Impact of system capital investment on O&M costs

ENGLP considers both capital and O&M expenditures over an asset life cycle to ensure optimal value is attained over the life of the asset. ENGLP's maintenance strategy is to minimize reactive and emergency-type work through efficient operations and an effective planned maintenance program, including predictive and preventative actions. ENGLP's customer responsiveness and system reliability are monitored continually to ensure that its maintenance strategy is effective.

Capital renewal investment, including replacement or restoration, may be required when it is not cost effective to manage the asset in an optimal manner. This effort is coordinated with ENGLP's capital project work so that where maintenance programs have identified matters which require capital investments, ENGLP may adjust its capital spending priorities to address those matters.

ENGLP's Integrity Management Program and Asset Management Plan (Appendix 1) includes expenditures to perform condition assessment of assets. Through this assessment the asset is confirmed to either be fit for service, fit for service with additional maintenance activities required or have the need to be replaced or restored requiring capital investment.

Further, the Integrity Management Program mentions direct inspection programs completed through leak surveys and surface corrosion surveys. This data is correlated with the age of the asset to form the asset condition. Leaks on assets are addressed depending on the circumstance and involve a combination of repair/restoration (O&M costs) or replacement (capital costs). To proactively mitigate this risk, ENGLP conducts annual leak surveys, cathodic protection read survey, depth of cover survey, and overall leak inspection survey for both steel and plastic piping and performs repairs according to a leak severity/classification method. Further, In-line inspection programs are conducted on the 6 inch steel line to reduce the frequency of failure and damage incidents associated with imperfections (e.g. metal loss, cracking, and material, manufacturing, and construction defects).

Overall, the system investments are not expected to have a significant impact on total O&M costs in the forecast period. ENGLP will proactively evaluate risk and criticality of the natural gas distribution assets and use this information in crafting maintenance and monitoring strategies. The utility will continue to assess and manage risks in accordance with ENGLP's risk management framework and in keeping with the more specific requirements of a System Integrity Management Program under CSA Z662.

7.0 Engineering Plan (ENGLP Aylmer System Integrity Study)

ENGLP engineering plan is represented by the 2023 Aylmer System Integrity Study completed by Cornerstone Energy Services. The purpose of both plans is to provide supporting background regarding ENGLP's forecast of capital expenditures.

ENGLP has contracted Cornerstone to perform a system integrity study and to evaluate and develop capital cost estimates for capital improvement projects that will enhance performance and capacity of the system. The ENGLP gas system is in need of both pressure and volumetric reinforcement in order to provide a stable and reliable source of natural gas for all of its current and anticipated customers through the year 2029. The Cornerstone study identifies requirements for system enhancement to meet load growth due to market penetration, population growth, or infrastructure expansion and identify projects that will provide the enhancements.

Appendix 2 details the Cornerstone ENGLP Aylmer System Integrity Study. Section 5.0 below highlights the capital expenditure investments being considered to support the engineering plan.

8.0 ENGLP Asset Management Plan

ENGLP 2025-2029 Asset Management Plan is represented as a stand alone document and built using guidance from the OEB's Filing Requirements for Natural Gas Rate Applications. The AMP outlines ENGLP's asset management policies and objectives; provides an overview of asset inventory and assessment of their conditions; risks, opportunities and strategies; and an overview of the asset planning process. The Asset Management Plan at ENGLP ensures that value is realized through its assets while managing risk and opportunity. The information is also used to guide for new and renewal capital as well as maintenance expenditures.

Appendix 1 details the ENGLP Aylmer Asset Management Plan.

Section 9.0 below highlights the capital expenditure investments being considered to support the asset management plan.

9.0 Proposed Investment Needs (Engineering and Asset Management Plan)

The Asset Plan establishes the requirements and estimates the related capital expenditures to support four primary kinds of asset-related investments - Customer Growth, System Reinforcements, System Integrity & Reliability including work on the dedicated 6inch steel line serving the Integrated Grain Processors Co-op customer ("IGPC").

9.1 Customer Growth

ENGLP delivers safe and reliable natural gas to approximately ten thousand customers which is forecasted to grow over the 5-year period of the USP. The operations services residential, commercial, industrial and agricultural customers within its franchise areas. Growth consists of the addition of new customers, customers converting from another fuel source to natural gas as well as upgrades to existing equipment's or services to accommodate load growth.

The first step in determining supply requirements is the development of a demand forecast. The demand forecast is based on the values provided by Elenchus Research Associates Inc. ("Power Advisory LLC") in its Weather Normalization and Distributions System Load Forecast.

The utility will service three main classes of customers: General Service, Seasonal and Contract customers. These customers fit under six rate classes that include:

- **General Service Customers:** Rate 1 (General Service Rate) and Rate 4 (General Service Peaking),
- **Contract Customers:** Rate 3 (Special Large Volume Contract Rate), Rate 5 (Interruptible Peaking Contract Rate) and Rate 6 (Integrated Grain Processors Co-Operative Aylmer Ethanol Production Facility), and
- **Seasonal Customers:** Rate 2.

The following tables provide ENGLP Customer Connection Forecast and Annual Customer Service Demand Forecast by Rate Class.

Table 4: ENGLP Forecast of Customer Connections

	2023 Actual	2024 Forecast	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	2029 Forecast
R1 Residential	9,318	9,448	9,578	9,708	9,838	9,968	10,097
R1 Industrial	79	80	81	83	84	86	88
R1 Commercial	580	585	590	595	600	605	605
R2 Seasonal	51	50	50	50	50	50	50
R3	4	5	5	5	5	5	5
R4	43	45	46	48	49	51	51
R5	4	4	4	4	4	4	4
R6	1	1	1	1	1	1	1
Total	10,080	10,218	10,355	10,494	10,631	10,770	10,900

Table 5: ENGLP Annual Customer Service Demand by Rate Class

	2023 Actual	2023 Normalized	2024 Forecast	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	2029 Forecast
R1 Residential	7,466,767	19,043,524	19,394,143	19,778,416	20,165,775	20,556,215	20,949,733	21,368,727
R1 Industrial	3,013,707	2,654,845	2,579,897	2,686,373	2,795,837	2,908,361	3,024,023	3,144,985
R1 Commercial	5,823,050	5,659,391	6,119,454	6,193,869	6,268,637	6,343,760	6,419,235	6,483,427
R2 Seasonal	869,131	869,131	832,281	832,281	832,281	832,281	832,281	832,281
R3	1,335,618	1,420,006	3,943,038	4,518,036	4,495,600	4,475,300	4,456,801	4,456,801
R4	2,227,329	2,227,329	2,225,219	2,542,296	2,623,115	2,706,504	2,792,543	2,876,320
R5	980,160	980,160	647,586	647,586	647,586	647,586	647,586	647,586
R6	5,345,852	65,345,852	65,345,852	65,345,852	65,345,852	65,345,852	65,345,852	65,345,852
Total	97,061,614	98,200,239	101,087,469	102,544,707	103,174,682	103,815,859	104,468,054	105,155,980

The Growth capital expenditure requirements for asset installation is based on customer growth forecast over the next 2023-2028 period. Capital investments such as material and labour costs are required to support the new customer connections. ENGLP projected customer growth forecast over the next 5-year period through information received from developers and municipalities. On average, the annual growth rate for each of the towns within the Aylmer distribution system was 2%. A town load represents consolidated loads of all the customers in corresponding town's district. Capital spending for non-town (rural) loads are assessed and analyzed on an individual basis. This involves analysis of whether new distribution mains or reinforcements to existing mains are required to service these loads.

Table 6 below summarizes detailed load allocations for each of town loads (per district regulator station) in the Aylmer distribution system.

Table 6: Load Allocations for town loads in Aylmer distribution system (2023, 2028)

	Town Loads (m3/hour)	
Towns	**2023 Estimate**	**2028 Estimate**
Aylmer East	902	984
Aylmer Beech St	1,430	1,560
Aylmer Roger-Talbot	385	420
Aylmer Bradley Creek	385	420
Aylmer Hacienda	385	420
Aylmer (Total)	3,488	3,805

Belmont (Total)	1,050	1,146
Brownsville - 3810 Brownsville - South Brownsville (Total)	132 121 252	144 132 275
Nilestown (Total)	175	192
Port Burwell East Port Burwell West Port Burwell (Total)	279 279 560	305 305 610
Port Bruce 1st Port Bruce 2nd Port Bruce (Total)	132 132 264	144 144 288
Springfield (Total)	410	448
Straffordville (Total)	263	287
Vienna (Total)	263	287

9.1.1 Customer Connections Feasibility

ENGLP is expected to provide natural gas services to residential and commercial/industrial customers requesting to connect to existing infrastructure. In order to determine feasibility, and avoid harm to existing ratepayers, the value of a project's revenues against its costs (EBO 188). ENGLP monitors and updates its customer additions forecasts annually through its planning process and in alignment with its Customer Connection policy. Economic feasibility for growth is based on EBO 188 guidelines applied to the investment portfolio. This includes community expansion projects which involve the installation of gas distribution assets to service communities that have not been previously provided with natural gas. These projects are driven by municipal interest and supported by an OEB approved funding mechanism.

When assessing the feasibility of a new individual customer connection or group of connections, ENGLP prepares a forecast of costs and revenues and assesses the overall financial viability using the guidelines in EBO 188 set out by the OEB. If the present value (PI) of revenues is equal to or greater than the present value of costs, the project is economically feasible and can be built. If the present value of revenues is less than the present value of costs, customers will be asked to pay a Contribution in Aid of Construction ("CIAC") which is the amount by which project costs must be paid by the customer to make the project feasible. For Natural Gas expansion to be undertaken either at the project or portfolio level, a PI of greater than 1 needs to be achieved. If it is less than 1, a customer contribution may be required in order to get the PI to be greater than one.

The amount calculated as a CIAC is project specific and depends on the overall costs and revenues for each project. The OEB has established feasibility guidelines and rules for calculating CIAC and ENGLP applies these methodologies to its own customer connection policies. If the customer chooses not to pay, the project does not proceed.

9.2 Distribution System Reinforcement

ENGLP conducts reinforcement projects in its system to maintain minimum system pressures for demand of gas to be met on design day conditions. These projects involve the installation of new gas infrastructure or modifications to existing gas assets to maintain system pressure, capacity and meet growth demands.

ENGLP conducts annual hydraulic simulations of the natural gas system using Cornerstone Energy Services. The hydraulic model uses pressure and flow measurement on the system during peak conditions experienced for the year. For large volume customers, hourly data is typically required and included within the analysis. The objective of the network design is to meet anticipated peak at temperature dependent design conditions. Load additions are modeled based on the design temperature. Reinforcements are based on the system's ability to meet minimum system pressures based on forecasted loads at key locations. This is based on 5-year forecasted growth to ensure the system has the security of supply and reliability needs to meet gas demands.

The ENGLP 2028 System Integrity simulations revealed potential gas supply shortcomings to meet prospective demand. Several options for increased delivery volume through Bayham, Dorchester and Lakeview stations, along with relevant piping upgrades, were analyzed and simulated. A list of proposed capital improvement projects to meet the 2028 demands have been developed and summarized below. Detailed business case justifications are provided for each project separately as part of the USP.

Table 7: Planned Large Customer Additions and System Reinforcement Projects

Project/Area	Project Description
Large Agricultural Customer Phase 1 and 2 Load (Southeast)	A large agricultural load has requested ENGLP to provide natural gas supply of 1,700m3/hr for Phase 1 of their operations, and 3,400m3/hr for Phase 2. The first step to reaching Phase 1 gas load requirements of 1,700 m3/hour includes installing approximately 2kms of 6inch MDPE pipe. This increases the current available capacity to the customer from 350m3/hour to 800m3/hour as well as provides availability for future upgrades to take place. The second step to reach Phase 1 load of 1,700 m3/hour (additional 900 m3/hour from step 1) by November 2024 involves taking gas supply from nearby Maricann Station from Clearbeach Resource Inc (an oil and gas exploration company based in London, Ontario which operates multiple gas drilling wells). Currently, numerous internal simulations are being conducted to check existing piping upgrades and station capacity increases would enable meeting Phase 2 gas demands.
5MW Power Plant Customer Addition (Carter Road, Aylmer)	This project involves CEM Engineering applying for the development of a 5MW natural gas fired power plant to participate in the IESO's LT1 RFP process. The main fuel source would be grid gas from ENGLP. In the future, there is potential to run RNG through it before it goes to the grid but that is hypothetical at this point. The preferred option to service this load with natural gas includes: • Upgrade assets at Bayham station to increase max flow from current 1,854 m3/hour to 2,300 m3/hour

	• Upgrade the current 4inch MDPE piping coming out of Bayham station to 6inch MDPE to the intersection of Talbot Line and Best Line (Length ~3.5 kms)
Port Burwell Low Pressure Reinforcement (Port Burwell)	In recent years, during periods of low temperatures and resulting record high natural gas demands, system pressures in the community of Port Burwell were well below system design and the utility was and continues to be at risk of unplanned customer outages. The situation will only get worse as demands increase and production from the connected wells continues to decline. To continue to ensure safe and reliable service to existing customers and support ongoing development in the area, reinforcement of the system is required and spending under this program is non-discretionary. The recommended reinforcement option to alleviate low pressures in the area involves: • Relocating the current Port Burwell Teall Hill regulator station ~2.5kms from its current location down south and • Upgrading the existing ~2.5kms of 2inch pipe to 4inch that feeds Port Burwell along Plank Road. The relocated Port Burwell Teall Hill regulator station will knock the existing 80psi inlet pressure to 30psi outlet in order to feed the community of Port Burwell.
South Belmont Pipe Addition (Belmont)	Cornerstone performed system integrity simulations for two different load cases: January peak flows/loads and fall peak flows/load for 2023 and 2028 growth forecast. Simulation of the southern stream suggests possible problems with the system pressure with the existing 3inch MDPE pipe from the intersection of Yorke Line and Elgin Road toward Belmont South station. The 3inch pipe going toward South Belmont along Yorke Street has

	insufficient pressure if the January 2028 peak flow were combined with all the interruptible customers' full consumption. Southern Belmont area needs reinforcement to improve piping capacity. The recommended option to improve pressures involves installing a new ~4km 4inch MDPE pipe along Wilson Road and north on Belmont Road to alleviate the congestion at central Aylmer district and low pressure in South Belmont. Simulation results suggested that a new 4inch main line not only resolved the South Belmont area problem but also improves pressure distribution at Aylmer and eastern central districts.

9.3 System Integrity and Reliability (Distribution Assets and Plastic Pipe)

ENGLP has a combined inspection and maintenance practice for field assets. Asset inspection and maintenance is designed to optimize the asset lifecycle until such time that the asset has reached a condition requiring refurbishment or replacement.

ENGLP's operations and maintenance strategy is to minimize reactive and emergency-type work through efficient operations and an effective planned maintenance program, including predictive and preventative actions. ENGLP's customer responsiveness and system reliability are monitored continually to ensure that its maintenance strategy is effective. This effort is coordinated with ENGLP's capital project work so that where maintenance programs have identified matters which require capital investments, ENGLP may adjust its capital spending priorities to address those matters. ENGLP constantly evaluates its maintenance data to adjust predictive and preventative actions with the ultimate objective being to reduce and minimize any emergency maintenance work.

Recently, ENGLP has invested in GIS and SCADA to provide an objective view of its assets that will lead to more efficient and optimized design, maintenance and investment activities. Inspection, maintenance and testing data will be entered into the GIS as attribute information for each piece of plan. Operating data will be collected through GIS and be made available for engineering analysis and service quality reporting.

ENGLP's Integrity Management Program ("IMP") contributes to extending the useful life of assets by identifying condition issues prior to occurrences of incidents. The weekly, monthly and annual inspection activities reduces the probability of pipeline failures and unplanned asset integrity issues. The program includes procedures to monitor for conditions that can lead to failures and includes a description of ENGLP's commitment to assess risks, identify risk reduction approaches and monitor results. ENGLP is constantly looking to update its IMP to ensure condition issues are identified and mitigated continuously using the Plan-Do-Check-Act methodology.

The condition methodology for distribution piping is through annual maintenance programs (Leak Surveys and Cathodic Protection Surveys) to monitor asset conditions. Steel distribution pipes are prone to internal and external corrosion when coatings and cathodic protection is lacking and are subject to annual leak and cathodic protection surveys. Steel mains under bridge crossings and plastic pipe in casing can also be exposed to road salt and seasonal ground movements that can affect its integrity over time. Many such casings can lack test points which prevents monitoring. To monitor, ENGLP completed monthly cathodic protection checks on bridge/railway crossings in the distribution system.

Overall, ENGLP's inspection and maintenance program is summarized in the table below:

Table 8: ENGLP Inspection and Maintenance Program

Program	Frequency
Gate and Regulating Stations	• Inspected Annually • No more than 18 months wait time for inspection of stations
Above Ground Valves	• Inspected Annually
Poly-Valves (underground valves)	• Inspected Annually
Regulatory and Filter Inspections on Local Production Wells	• Inspected Annually (ENGLP side)
Electronic Volume Correctors at Large Customer Station	• Calibration Checks Annually (Temperature, Pressure)
Pressure Factor Metering (PFM) Regulators	• Tobacco Customers – Inspected Annually • 10psi PFM's – Inspected once every 2 years • 5psi and 2psi PFM's – Inspected once every 3 years

Station Odorant Checks	• District Stations Inspected Monthly • Lakeview Station Inspected Weekly • RNG Station Inspected Weekly • Local Production Wells Inspected Weekly
Dew Point Checks	• Lakeview and RNG Station Inspected Weekly
Cathodic Protection Checks	• Bridge/Railway Crossings Inspected Monthly
Hetek Leak Survey	• Conducted Annually on the Aylmer Distribution System and Dedicated 6inch Steel IGPC Pipeline
Public Building Survey	• Conducted Annually in the winter time period to check for underground leaks migrating to public buildings

9.4 Integrated Grain Processors Co-op (IGPC)

ENGLP's owns and operates a roughly 30km 6 inch NPS steel pipeline that serves a single customer, IGPC's ethanol plant in Aylmer. The pipeline constructed in 2007 by Natural Resource Gas Limited ("NRG") has a history of integrity issues associated with the last 400 metre section. The integrity issues were concerns associated with the original installation method of this pipeline section under hard surfaces, such as roadways and driveways (requiring Horizontal Directional Drilling), as well as lack of proper pipeline coating when originally installed. In 2016, NRG experienced a leak on this section and in October 2020, ENGLP experienced another leak on this section that needed to be cut out and replaced. As a result, ENGLP undertook pipeline pigging activities between the years 2020-2022 as part of its Integrity Management Program to examine areas of the pipeline that may be weakened, at risk of leak and have severe overall corrosion and integrity issues.

The pigging activities (series of cleaning and inspection tool runs) was a costly endeavour requiring multiple runs over successive years to finally get an integrity profile of the pipeline in order for ENGLP to develop a prudent asset management plan. The first attempted Low Res Geometry tool run was successful in 2021, however, it was determined that a few sections of the pipeline would need to be cut out and replaced as they did not meet the specifications required to successfully run the Magnetic Flux Leakage (MFL) tool. A second run conducted in 2021 of the MFL tool resulted in the inspection tool coming apart because it got hung up on a difficult valve configuration. In 2022, a successful MFL tool run was completed that provided key integrity data about the pipeline. The pigging activities, as per CSA Z662 Code, were examples of costs that NRG did not consider as part of its integrity management program that ENGLP could not ignore.

Overall, the MFL tool results determined that 76 metal loss/corrosion features (Internal and External) exist on the IGPC pipe. The majority of the features identified along the 30km stretch were minor (20-50% metal loss) in nature and from an integrity management perspective, it was assessed that the pipeline could be operated safely and reliably until further assessments and inspection activities take place. The results also confirmed that there are 16 minor and 1 major – 78% metal loss features on this 400m section of pipe.

In April 2024, ENGLP, working with its alliance partner, Aecon, executed on the cut out and replacement of the 78% metal loss feature. Further, capital project placeholders in 2025 and 2026 have been included in the USP to conduct integrity digs on the other significant (>50% metal loss) features on the 400m section of pipe. ENGLP operations and engineering will explore using less costly options to repair individual features, including the use of composite sleeves that can structurally reinforce or permanently restore external anomalies for metal loss features less than 80%.

The MFL tool results and pipeline integrity profile that ENGLP received in 2022 is considered to be “baseline”. TDW, who completed the MFL run for ENGLP in 2022, is able to re-run the same tool and compare the results and provide corrosion growth analysis. This re-run work would involve: assessing any changes to metal losses reported between old and new inspection data; conducting corrosion diagnosis to determine possible corrosion growth mechanisms; applying corrosion growth rates to the data; and issuing a comparison report between old and new. From an O&M perspective, ENGLP plans to re-run the MFL tool either in 2026 or 2027 as part of its integrity program.

10.0 Long Term Economic and Planning Assumptions

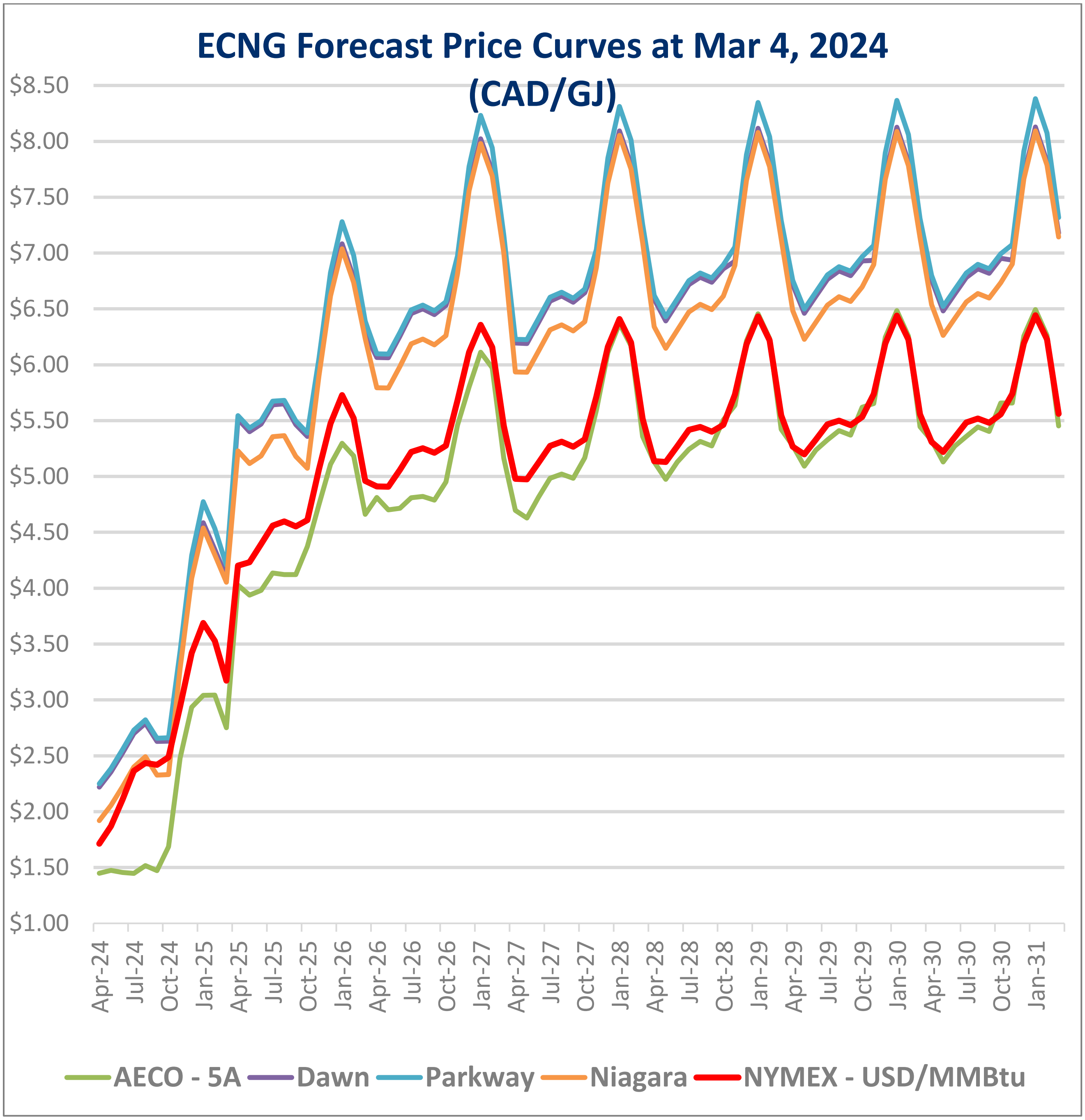
10.1 Natural Gas Price Signals and Expectations

The North American fundamental drivers for natural gas are demand, supply, storage and in a more limited/indirect way crude oil and underlying currency foreign exchange. Natural gas primarily flows into the Dawn Hub ("Dawn") from the WCSB and future prices set by the New York Mercantile Exchange (NYMEX) for deliveries at Henry Hub are seen to be the primary price for the North American market.

There are no new pipeline projects expected in the Dawn connected infrastructure in the near future that would shift the supply and demand dynamics. With its multiple pipeline connections to the largest supply basins in N.A, the Dawn market can be vulnerable to pipeline contracting, renewals and long-term toll negotiations between pipelines and its shippers. Within the next 5 years, some long-term contracts may not be renewed under the same terms. This change in contracting can alter the flow dynamics into and out of Dawn which will influence the commodity price of gas.

Nearer term Dawn basis forward pricing curves are showing trends that are at a larger discount to NYMEX of late likely due to the excess storage gas remaining from the winter at Dawn and at sites neighboring Midwest US (mostly Michigan). The mild weather in early 2023 also resulted in lower demand from Ontario gas fired power generation fleet, however, we expect similar-to-higher demand as was seen last summer to back up continuing nuclear refurbishments in Ontario plus supporting modest increased power demand year-over-year. The forward price curves at Dawn continue to trade at a lesser discount to NYMEX in winters and summers starting November 2026 likely due to modest demand growth and/or risk of long-term pipeline contracts not being fully renewed.

Figure 1: Long-Term Natural Gas Prices



10.2 Federal Carbon Pricing Forecast

As part of the Government of Canada's Federal Carbon Pricing Program ("FCPP"), a federal carbon pricing system has been implemented in Ontario, under the Greenhouse Gas Pollution Pricing Act, with the following features:

For larger industrial facilities, an output-based pricing system for emissions-intensive trade-exposed ("EITE") industries applied in January 2019. This will cover facilities emitting 50,000 tonnes of carbon dioxide equivalent ("CO2e") per year or more, with the ability for smaller EITE facilities that emit 10,000 tonnes of CO2e per year or more to voluntarily opt-in to the system; and,

A charge applied on applicable fossil fuel deliveries, as set out in the Greenhouse Gas Pollution Pricing Act, Part 1, effective April 1, 2019.

ENGLP continues to file annual applications for FCPP rates and recoverable costs, effective April 1, most recently EB-2023-0274. ENGLP will continue to monitor and assess the potential impact of the FCPP on future customer consumption and conversion decisions.

Table 9: Federal Carbon Charge Rates

Year	Price of Carbon ($/t$CO_2$e)	FCC Rate (cents/m^3)
2024	80	15.25
2025	95	18.11
2026	110	20.97
2027	125	23.83
2028	140	26.69
2029	155	29.54
2030	170	32.40

11.0 Continuous Improvement

ENGLP will continue to seek opportunities to build continuous improvement practices in its processes, goals and objectives, in particular, its gas supply obligations, asset management plans, construction practices, and alliance partner agreements.

The continuous improvement to the supply planning process undertaken by ENGLP is an important element of the transparency objective of the Framework. ENGLP continues to proactively evaluate new supply and transportation options, proactively identify new opportunities to meet its gas supply obligations while meeting the Framework assessment criteria as well as continue to review and improve the information it receives for market outlook and forecasting purposes.

ENGLP is committed to the effective stewardship of its assets through policy and principles and is committed to applying asset management practices to effectively manage the life cycle of its assets. This involves developing maintenance, operation, and reliability strategies as well as capital programs consistent with its Asset plan guiding principles. The Asset Management Program is a component of the Integrity Management Program and ENGLP continues to evolve this program based upon industry best practices and incident learnings.

Reviews of processes and key documents are conducted with the intention of satisfying the following objectives:

- Reflect changes due to regulatory requirements.
- Change management related to pipeline reconfiguration.
- Incorporate better technologies or new developments in management practices.
- Refine approaches as driven by new learnings from operational data.
- Optimize cost of activities.

Continuous improvement of the program also includes the audit of the entire scope of the Pipeline Integrity Department, which is formally facilitated by the ENGLP Audit group or through audits conducted by regulatory agencies, i.e. TSSA, MOL, or MECP.

12.0 Public Policy Objectives (ENGLP Gas Supply Plan)

12.1 Renewable Natural Gas (RNG)

ENGLP recognizes the importance of Greenhouse Gas (GHG) reduction across the province, as well as the role that ENGLP plays in supporting the achievement of GHG emission reduction targets. As a result, ENGLP supports the development of an RNG market and facilitates inclusion of RNG in its gas supply portfolio.

In Q2 of 2023, ENGLP received RNG into its Aylmer distribution system. However, ENGLP is not purchasing the environmental attributes of this RNG gas and will not take ownership of the environmental attributes generated from the production of RNG. This arrangement ultimately allows for development of RNG production within Ontario. It also provides ENGLP a learning opportunity on how to transact and procure RNG without significant cost impact to the rate base.

One of the key learnings to date is that RNG projects tend to have relatively steady production volumes throughout the year, which presents a challenge to system operations during the summer period when consumption is low, especially for systems like Aylmer where it is not possible for the RNG to physically leave the system. This limits the size and the number of RNG projects to be considered and implemented in the Aylmer system.

12.2 Demand Side Management (DSM)

ENGLP had plans to submit a DSM proposal in its next cost of service filing for Aylmer (or in a separate standalone proceeding), where the plan, the financial impacts and ratemaking implications would be addressed. While this was the intent, ENGLP is not currently ready to do so. This is largely attributable to the transitional state of the DSM framework for natural gas customers in Ontario, and specially the Enbridge DSM supplemental application to be filed in 2024.

After engaging third party vendors, as well as investigating potential collaboration with both Enbridge and the IESO (in response to the Minister of Energy's letter of direction), ENGLP believes that a collaborative, consistent program offering would be of best interest to its customers and the most effective way to deliver this would be through a shared arrangement with a larger provider.

In order for a DSM program offering to be successful, ENGLP would require several additional resources to prepare an application, launch, fulfill and meet the reporting obligations, which would lead to higher costs for customers if all of these roles were to be filled internally. ENGLP remains open to further collaboration discussions with the IESO and Enbridge to help achieve economies of scale in the DSM portfolio.

12.3 Integrated Resource Planning (IRP)

This USP update does not include potential impacts of future IRP projects as there are currently no plans to implement IRPs in Aylmer.

13.0 Other

13.1 Projects/Programs Subject to Leave to Construct (LTC)

In constructing pipelines, ENGLP follows the guidelines prescribed in the OEB Act that requires a Leave to Construct application for projects that cost more than the amount prescribed by regulations (current threshold is $2 million). Currently, there are no investments identified in this USP period that would require a LTC application. This includes projects involving relocation or reconstruction of an existing pipeline.

The only project that has the possibility of being close to the $2 million threshold is the Large Agricultural Customer Greenhouse Phase 2 Load. The combination of infrastructure requirements to hit Phase 1 and 2 loads for the customer could see the project threshold spend go above $2 million. ENGLP will continue to track this project closely during the scope of this USP period.

13.2 Projects Undertaken in Relation to Initiatives from the Minister of Energy

The Ontario government enacted policy to assist in the development of new infrastructure to allow natural gas service to reach rural communities. In 2016 the OEB issued a decision in its generic proceeding on new community expansion which indicated utilities could propose an SES over and above existing rates. Community expansion projects are subject to a 10-year rate stability period during which the utility bears the risk of its customer attachment forecast and revenue requirement.

ENGLP has been actively working to bring secure, reliable and affordable natural gas to unserved communities. The recently completed the Southern Bruce project represents one of the largest community expansion projects awarded to date (EB-2018-0263). Of note, the Southern Bruce project has been approved under a separate 10-year regulatory compact and rate structure and its impacts are not directly considered in this USP.

ENGLP will continue to work to expand access to natural gas service to communities who are not currently connected to a natural gas distribution, and pursuant to ENGLP's obligation to serve, to any customers or communities who request natural gas service.

14.0 Capital Expenditure Justifications (Program/Project Specific)

This section includes the material justification for projects by year from 2025-2029 and follows the materiality threshold stated in Chapter 2 of the Filing Requirements for Natural Gas Rate Applications issued by the Board dated February 2017.

All material projects have the following business case information provided:

a) Justification and Need Background
b) Alternatives Considered
c) Scope of recommendation
d) Cost Basis
e) Timelines and Milestones
f) Execution Risks
g) Prelim Execution Strategy

14.1 Material Investments

Project or Program	B 2025 Test Year	C 2026	D 2027	E 2028	F 2029
Investment Category - System Access					
Main Additions - Steel (Distribution Plant)					
Main Additions - Plastic (Distribution Plant)	$ 446,850	$ 473,960	$ 485,410	$ 508,440	$ 533,050
Customer Contribution	$ (25,000)	$ (25,000)	$ (26,250)	$ (27,560)	$ (28,940)
Main Additions - Plastic (Net Contributions)	$ 421,850	$ 448,960	$ 459,160	$ 480,880	$ 504,110
Service Additions - Plastic	$ 723,520	$ 792,830	$ 821,140	$ 867,225	$ 901,825
Customer Contribution	$ (43,750)	$ (43,750)	$ (45,500)	$ (47,775)	$ (50,225)
Service Additions - Plastic (Net Contributions)	$ 679,770	$ 749,080	$ 775,640	$ 819,450	$ 851,600
Meter Additions	$ 156,870	$ 184,510	$ 201,990	$ 205,210	$ 210,600
Regulator Additions	$ 127,160	$ 155,400	$ 156,390	$ 169,520	$ 184,300
EZ Grow 6" Pipeline Install					
EZ Grow Phase 1 and Phase 2 Load	$ 500,000				
5MW Power Plant Customer Addition		$ 1,124,220			
Customer Contribution		$ (404,705)			
5MW Power Plant Customer Addition (net contributions)		$ 719,515			
Total	$ 1,885,650	$ 2,257,465	$ 1,593,180	$ 1,675,060	$ 1,750,610
Investment Category - System Renewal					
Main Replacements	$ 47,320	$ 54,660	$ 52,580	$ 62,760	$ 63,030
Service Replacements	$ 79,930	$ 78,910	$ 66,820	$ 72,010	$ 77,280
Contribution	$ (3,500)	$ (3,500)	$ (3,500)	$ (3,500)	$ (3,500)
Service Replacements (Net Contributions)	$ 76,430	$ 75,410	$ 63,320	$ 68,510	$ 73,780
Regulating Station Upgrades and Maintenance	$ 82,830	$ 194,270	$ 211,250	$ 212,260	$ 209,180
Meter Replacements	$ 820,990	$ 799,260	$ 446,050	$ 437,450	$ 99,740
Regulator Replacements	$ 128,580	$ 140,020	$ 135,320	$ 145,210	$ 117,560
IGPC Pipeline Asset Management	$ 300,000	$ 300,000			
Total	$ 1,456,150	$ 1,563,620	$ 908,520	$ 926,190	$ 563,290
Investment Category - System Service					
SCADA	$ 35,050	$ 39,950	$ 43,030	$ 46,540	$ 50,050
Port Burwell Low Pressure Reinforcement	$ 415,000				
South Belmont Pipe Addition			$ 362,000	$ 362,000	
Total	$ 450,050	$ 39,950	$ 405,030	$ 408,540	$ 50,050
Investment Category - General Plant					
Fleet Vehicle	$ 75,520	$ 80,000	$ 87,300	$ 91,510	$ 95,700
IT Hardware, OT Cyber Security and Mobile Apps	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000
Small Tools and Work Equipment	$ 23,030	$ 22,000	$ 22,300	$ 22,510	$ 22,700
Building Refurbishments	$ 123,530				
Total	$ 272,080	$ 152,000	$ 159,600	$ 164,020	$ 168,400
Total	**$ 4,063,930**	**$ 4,013,035**	**$ 3,066,330**	**$ 3,173,810**	**$ 2,532,350**

Project Name:	**System Access - Main Additions (Program)**		
Project Number:	N/A	**Capitalization Criteria:**	Extension
Project Initiator:	Mark Emmanuel	**Enterprise Project Driver :**	2. Growth/Customer Requirements
Project Manager:	Mark Emmanuel	**Primary BU:**	ENGLP – 5B
Project Sponsor(s):	Darren McCrank Director, Ontario Operations	**Filing/Regulatory Reference:**	System Access

FUNDING BY YEAR						
	2025	**2026**	**2027**	**2028**	**2029**	**TOTAL**
Capital Expenditure ($)	**$446,850**	**$473,960**	**$485,410**	**$508,440**	**$533,050**	**$2,447,710**
External Contribution ($)	**($25,000)**	**($25,000)**	**($26,250)**	**($27,560)**	**($28,940)**	**($132,750)**
Net Capital Cost TOTAL	**$421,850**	**$448,960**	**$459,160**	**$480,880**	**$504,110**	**$2,314,960**
Capital Addition (%)	**100%**	**100%**	**100%**	**100%**	**100%**	
Operating Expenditure ($)	**0**	**0**	**0**	**0**	**0**	**0**

1. Background and Justification

The Main Additions program accounts for the installation of new pipeline mains for the purposes of serving new customers, as well as minor reinforcement additions to the system in order to improve reliability. The estimated annual capital spend is estimated based on management judgement and average historical spending.

Individual projects under the program to install new mains with the primary purpose of serving new customers are subject to an economic test as required by the OEB, the calculation of a profitability index (PI) value. If the PI value is less than 1, a contribution in aid of construction is calculated and paid by the new customer(s).

Individual projects under the program for the purposes of system reinforcement are evaluated, planned and prioritized based on customer need and risk. Projects may be added, deferred and/or reprioritized within the overall program, and approved program budget, as circumstances dictate.

The gas main additions are installed using a trenchless plow, open trench or directional drilling and contracted out to our third-party Alliance Contractor (Aecon Utilities). Installation labor and contractor cost estimates included in the estimated program are based on our existing Master Service Agreement rates with Aecon Utilities with inflationary measures added year by year. ENGLP internal staff complete the final inspection and tie-ins to the system.

The forecast for new main installations involves 2,500 metres of 2inch and approx. 500 metres of 4inch and cost estimates include all materials, labor and equipment. Costs to install service lines and risers to connect new customers to the system are captured separately under the Annual Service Additions program. Work on the 6" steel main supplying the IGPC ethanol plant is not included under this program and would be chartered separately, if required.

2. Alternatives Considered

This program accounts for the costs to provide new customers with access to natural gas service. Provided the system has the capacity to service the new customer(s) and they are willing to pay any required contribution in aid of construction, spending is generally non-discretionary.

3. Scope of Recommended Option

The Main Additions program accounts for the costs to provide new customers with access to natural gas service. Provided the system has the capacity to service the new customer(s) and they are willing to pay any required contribution in aid of construction, spending is generally non-discretionary.

Program spending for the purposes of minor system reinforcement is required to maintain system integrity and mitigate risk, helping to ensure the utility can continue to provide safe and reliable natural gas service. This spending is generally discretionary and projects may be added, deferred and/or reprioritized within the overall program, and approved program budget, as circumstances dictate.

4. Cost and Cost Basis

Costs have been estimated based on historical experience, current Master Service Agreement rates with Aecon Utilities, plus inflationary impacts. Costing for the Mains Addition program has been evenly spread over the USP period to ensure ENGLP has the resources and materials to ensure project completion on time.

5. Timelines and Milestones

The Main Additions program are slated to be completed within the System Access annual program 2025-2029 budget years. The engineering and procurement of these projects is be completed in advance to facilitate the construction of the capital projects.

6. Execution Risks

Program spending for the purposes of minor system reinforcements are required to maintain system integrity and mitigate risk, helping to ensure the utility can continue to provide safe and reliable natural gas service. This spending is generally discretionary and projects may be added, deferred and/or reprioritized within the overall program, and approved program budget, as circumstances dictate.

This program accounts for the costs to provide new customers with access to natural gas service and, as such, spending under the program is generally non-discretionary. Overall, there are no risks identified that would have a potential impact to project cost, schedule and performance criteria.

7. Preliminary Execution Strategy

Develop a list of main addition projects to be completed in the budget year with plenty of lead time. Once the USP is approved, ENGLP will utilize internal and external sources for each budget year to complete the projects from engineering to construction. This will allow ENGLP to complete main addition projects while maintaining internal resources to complete other system renewal and system access projects (service additions, meter additions, regulator additions etc.). Any approvals (MTO for example) will be completed during the engineering and design process of the main addition projects.

Project Name:	System Access - Service Connection Additions (Program)		
Project Number:	N/A	Capitalization Criteria:	Creation/Acquisition
Project Initiator:	Mark Emmanuel	Enterprise Project Driver :	2. Growth/Customer Requirements
Project Manager:	Mark Emmanuel	Primary BU:	ENGLP – 5B
Project Sponsor(s):	Darren McCrank Director, Ontario Operations	Filing/Regulatory Reference:	System Access

FUNDING BY YEAR						
	2025	2026	2027	2028	2029	TOTAL
Capital Expenditure ($)	$723,520	$792,830	$821,140	$867,225	$901,825	$4,106,540
External Contribution ($)	($43,750)	($43,750)	($45,500)	($47,775)	($50,225)	($231,000)
Net Capital Cost TOTAL	$679,770	$749,080	$775,640	$819,450	$851,600	$3,875,540
Capital Addition (%)	100%	100%	100%	100%	100%	
Operating Expenditure ($)	0	0	0	0	0	0

1. Background and Justification

The Service Connections Additions program accounts for the materials and installation costs of new natural gas services to connect new customers to the system. It also includes the lifecycle replacement of existing services, although this represents a small fraction of the overall program costs.

The number of new service connections is dependent on factors such as developer activity, the extension of mains into previously un-serviced areas, and fuel costs. This number has reduced to approximately 175 new connections in recent years. New connections are 85 to 90 percent residential customers and the remainder larger commercial or industrial customers. The estimated program costs are based on this forecast.

The service installation includes a punch tee coupling to connect to the main, excess flow valve, polyethylene (PE) service line (typically ½”), and riser and meter bar. Typical service lines (½”) are installed using a trenchless plow and small excavator by ENGLP operations. Larger service line installations, including directional drilling, are contracted out to our third-party Alliance Contractor (Aecon Utilities). Installation labor and contractor cost estimates included in the estimated program are based on our existing Master Service Agreement rates with Aecon Utilities with inflationary measures added year by year.

Individual service connections are evaluated, planned and prioritized based on customer need and risk. Projects may be added, deferred and/or reprioritized within the overall program, and approved program budget, as circumstances dictate.

2. Alternatives Considered

This program accounts for the costs to provide new customers with access to natural gas service. Provided the system has the capacity to service the new customer(s) and they are willing to pay any required contribution in aid of construction, spending is generally non-discretionary.

3. Scope of Recommended Option

The Service Connections Additions program accounts for the materials and installation costs of new natural gas services to connect new customers to the system. It also includes the lifecycle replacement of existing services, although this represents a small fraction of the overall program costs.

Program spending for the purposes of service connections required to maintain system integrity and mitigate risk, helping to ensure the utility can continue to provide safe and reliable natural gas service. This spending is generally discretionary and projects may be added, deferred and/or reprioritized within the overall program, and approved program budget, as circumstances dictate.

4. Cost and Cost Basis

The cost of service installation of $4,500 on average is based on Aecon's average of time and equipment cost, ENGLP's internal labor and material cost along with any yearly inflationary impacts. Aecon's estimated average of time and equipment cost is based on the current Master Service Agreement rates with ENGLP. The cost of a service is influenced by many factors such as the length of service, the size of service, the time of year, and whether this is in a built up area (requiring civil works or drilling) or new build area (open trench) which can make a year over year comparison challenging.

Costing for the Service Connection Additions program has been evenly spread over the USP period to ensure ENGLP has the resources and materials to ensure project completion on time.

5. Timelines and Milestones

The Service Connection Additions program are slated to be completed within the System Access annual program 2025-2029 budget years. The engineering and procurement of these projects is be completed in advance to facilitate construction.

6. Execution Risks

This program accounts for the costs to provide new customers with access to natural gas service and, as such, spending under the program is generally non-discretionary. Overall, there are no risks identified that would have a potential impact to project cost, schedule and performance criteria.

7. Preliminary Execution Strategy

Develop a list of service connections to be completed in the budget year with plenty of lead time. Once the USP is approved, ENGLP will utilize internal and external sources for each budget year to complete the projects from engineering to construction. This will allow ENGLP to complete service connections while maintaining internal resources to complete other system renewal and system access projects (service additions, meter additions, regulator additions etc.).

Project Name:	System Access - Meter Additions (Program)		
Project Number:	N/A	Capitalization Criteria:	Creation/Acquisition
Project Initiator:	Mark Emmanuel	Enterprise Project Driver :	2. Growth/Customer Requirements
Project Manager:	Mark Emmanuel	Primary BU:	ENGLP – 5B
Project Sponsor(s):	Darren McCrank Director, Ontario Operations	Filing/Regulatory Reference:	System Access

FUNDING BY YEAR						
	2025	2026	2027	2028	2029	TOTAL
Capital Expenditure ($)	$156,870	$184,510	$201,990	$205,210	$210,600	$959,180
External Contribution ($)						
Net Capital Cost TOTAL	$156,870	$184,510	$201,990	$205,210	$210,600	$959,180
Capital Addition (%)	100%	100%	100%	100%	100%	
Operating Expenditure ($)	0	0	0	0	0	0

1. Background and Justification

The Meter Addition program accounts for the purchase and installation costs of natural gas meters for new customer connections. The number of new connections is dependent on factors such as developer activity, the extension of mains into previously un-serviced areas, and fuel costs but has averaged approximately 175 new connections in recent years. New connections are 85 to 90 percent residential customers and the remainder larger commercial customers. The estimated program costs are based on this forecast.

Meter costs are based on updated pricing received from vendors. Sizes 250, 425 and 630 SCFH come from Honeywell (Elster) and all the larger meters come from GE (Dresser) and Romet. The OPCO regulators manufacturer is Pietro Fiorentini. The estimated program costs are based on a count of 175 residential meters along with a few larger commercial/industrial customer meters within the years of 2025, 2026, 2027, 2028 and 2029.

2. Alternatives Considered

ENGLP is required to ensure that meters are installed for new customers, as per the requirements of Measurement Canada, and comply with meter accuracy obligations prescribed under the Electricity and Gas Inspection Act. Spending under this program is non-discretionary.

3. Scope of Recommended Option

The Meter Addition program accounts for the purchase and installation costs of natural gas meters for new customer connections. Measurement Canada approves natural gas meters to be used for billing purposes and establishes the requirements related to service life. A new meter is verified for accuracy and sealed by an accredited body prior to being placed into service.

The number of new connections is dependent on factors such as developer activity, the extension of mains into previously un-serviced areas, and fuel costs but has averaged approximately 175 new connections in recent years. New connections are 85 to 90 percent residential customers and the remainder larger commercial customers. The estimated program costs are based on this forecast.

Program spending for the purposes of meter installations are required to maintain system integrity and mitigate risk, helping to ensure the utility can continue to provide safe and reliable natural gas service. This spending is generally non-discretionary and projects may be added, deferred and/or reprioritized within the overall program, and approved program budget, as circumstances dictate.

4. Cost and Cost Basis

Costs have been estimated based on historical experience, plus inflationary impacts The estimated program costs are based on a count of 175 residential meters along with a few larger commercial/industrial customer meters within the years of 2025, 2026, 2027, 2028 and 2029.

5. Timelines and Milestones

The Meter Additions program is slated to be completed within the System Access annual program 2025-2029 budget years. The engineering and procurement of these projects is be completed in advance to facilitate the construction of the capital work.

6. Execution Risks

Program spending for the purposes of meter additions are required to maintain system integrity and mitigate risk, helping to ensure the utility can continue to provide safe and reliable natural gas service. This spending is generally non-discretionary and projects may be added, deferred and/or reprioritized within the overall program, and approved program budget, as circumstances dictate. Overall, there are no risks identified that would have a potential impact to project cost, schedule and performance criteria.

7. Preliminary Execution Strategy

Develop a list of meter additions completed in the budget year with plenty of lead time. Once the USP is approved, ENGLP will utilize internal and external sources for each budget year to complete the projects from engineering to construction. This will allow ENGLP to complete meter additions while maintaining internal resources to complete other system renewal and system access projects (service additions, main additions, regulator additions etc.).

Project Name:	**System Access - Regulator Additions (Program)**		
Project Number:	N/A	**Capitalization Criteria:**	Creation/Acquisition
Project Initiator:	Mark Emmanuel	**Enterprise Project Driver :**	2. Growth/Customer Requirements
Project Manager:	Mark Emmanuel	**Primary BU:**	ENGLP – 5B
Project Sponsor(s):	Darren McCrank Director, Ontario Operations	**Filing/Regulatory Reference:**	System Access

FUNDING BY YEAR						
	2025	**2026**	**2027**	**2028**	**2029**	**TOTAL**
Capital Expenditure ($)	**$127,160**	**$155,400**	**$156,390**	**$169,520**	**$184,300**	**$792,770**
External Contribution ($)						
Net Capital Cost TOTAL	**$127,160**	**$155,400**	**$156,390**	**$169,520**	**$184,300**	**$792,770**
Capital Addition (%)	**100%**	**100%**	**100%**	**100%**	**100%**	
Operating Expenditure ($)	**0**	**0**	**0**	**0**	**0**	**0**

1. Background and Justification

The Regulator Addition program accounts for the purchase of pressure regulators and relief valves for new services within the natural gas distribution system. Pressure regulators and relief valves are used to control pressures within the distribution system and on residential, commercial and industrial service connections, and prevent overpressure and damage to pipelines and downstream equipment.

Regulator costs are based on updated pricing received from vendors. The estimated program costs are based on a count of 175 residential regulators along with a few larger commercial/industrial customer regulators within the years of 2025, 2026, 2027, 2028 and 2029.

2. Alternatives Considered

As control and process safety devices, pressure regulators and relief valves must be maintained in working order to prevent the overpressure and failure of pipelines and downstream equipment.

3. Scope of Recommended Option

The Regulator Addition program accounts for the purchase of pressure regulators and relief valves for new services within the natural gas distribution system. Pressure regulators and relief valves are used to control pressures within the distribution system and on residential, commercial and industrial service connections, and prevent overpressure and damage to pipelines and downstream equipment.

Regulator costs are based on updated pricing received from vendors. The estimated program costs are based on a count of 175 residential regulators along with a few larger commercial/industrial customer regulators within the years of 2025, 2026, 2027, 2028 and 2029.

Program spending for the purposes of regulator installations are required to maintain system integrity and mitigate risk, helping to ensure the utility can continue to provide safe and reliable natural gas service. This spending is generally non-discretionary and projects may be added, deferred and/or reprioritized within the overall program, and approved program budget, as circumstances dictate.

4. Cost and Cost Basis

Costs have been estimated based on historical experience, plus inflationary impacts The estimated program costs are based on a count of 175 residential regulators along with a few larger commercial/industrial customer meters within the years of 2025, 2026, 2027, 2028 and 2029.

5. Timelines and Milestones

The Regulator Additions program is slated to be completed within the System Access annual program 2025-2029 budget years. The engineering and procurement of these projects is be completed in advance to facilitate the construction of the capital work.

6. Execution Risks

Program spending for the purposes of regulator additions are required to maintain system integrity and mitigate risk, helping to ensure the utility can continue to provide safe and reliable natural gas service. This spending is generally non-discretionary and projects may be added, deferred and/or reprioritized within the overall program, and approved program budget, as circumstances dictate. Overall, there are no risks identified that would have a potential impact to project cost, schedule and performance criteria.

7. Preliminary Execution Strategy

Develop a list of regulator additions completed in the budget year with plenty of lead time. Once the USP is approved, ENGLP will utilize internal and external sources for each budget year to complete the projects from engineering to construction. This will allow ENGLP to complete regulator additions while maintaining internal resources to complete other system renewal and system access projects (service additions and replacements, main additions and replacements, meter additions and replacements etc.).

Project Name:	System Access - Large Agricultural Customer Phase 1 and 2 Load (Project)		
Project Number:	N/A	Capitalization Criteria:	Creation/Acquisition
Project Initiator:	Mark Emmanuel	Enterprise Project Driver :	2. Growth/Customer Requirements
Project Manager:	Mark Emmanuel	Primary BU:	ENGLP – 5B
Project Sponsor(s):	Darren McCrank Director, Ontario Operations	Filing/Regulatory Reference:	System Access

	FUNDING BY YEAR						
	2024	2025	2026	2027	2028	2029	TOTAL
Capital Expenditure ($)	$1,050,000 + $670,000 (Phase 1 Load)	$500,000 (Phase 2 Load) - Tentative					$1,720,000 (Phase 1) $500,000 (Phase 2)
External Contribution ($)							
Net Capital Cost TOTAL							
Capital Addition (%)	100%						
Operating Expenditure ($)	0	0	0	0	0		0

1. Background and Justification

A large agricultural customer has requested ENGLP to provide natural gas supply of 1,700m3/hr for Phase 1 of their operations, and 3,400m3/hr for Phase 2 that will become a large Rate 3 commercial customer in the Aylmer distribution system.

The first step to reaching Phase 1 gas load requirements of 1,700 m3/hour includes installing approximately 2kms of 6” P.E. pipe along with trace wire and all associated valves, couplings, labour, overhead and QA/QC. This project is being undertaken under AECON MSA winter rates due to the urgency of the customer need in February 2024. Upgrading the piping from 2” to 6” increases the current available capacity to the customer from 350m3/hour to 800m3/hour as well as provides availability for future upgrades take place to meet the Phase 1 and Phase 2 demands of the customer. The total cost of the project is $1,047,770 including contingency. The cost breakdown for the capital infrastructure needed to reach 800 m3/hour has been provided in the next section.

This pipeline upgrade project will increase gas flow in early 2024 to 800m3/hr. The second step to reach Phase 1 load of 1,700 m3/hour (additional 900 m3/hour from step 1) by November 2024 involves identifying practicable enhancements of Aylmer distribution system to meet that increased customers' demands. The most practical solution involves taking gas supply from nearby Maricann Station from Clearbeach Resource Inc (an oil and gas exploration company based in London, Ontario which operates multiple gas drilling wells). The overall solution involves a 4" P.E. pipe to be installed from the Maricann station south to Walsingham Townline Road and then east on Walsingham Townline Rd on the South side parallel to the existing 6" line. Clearbeach will be providing outlet pressure of 50psi from the Maricann station supply point. Further, a regulating station will be installed to regulate pressure down from 50psi to 10psi near the customer site transfer point.

Note: the project was not contemplated in the original ENGLP Cost of Service filing with the OEB and was subject to the EBO-188 calculations to determine whether customer contributions are required. Due to the large revenue projected to come from this operation, the PI is greater than one. It would take the customer to consume less than 15% of their expected consumption profile to drop the P.I. to below 1.

This pipeline upgrade project will increase gas flow in early 2024 to 800m3/hr. Further, gas supply from nearby Maricann Station from Clearbeach Resource will increase gas flow to 1,700 m3/hr to meet Phase 1 demand. Lastly, a placeholder ($500k) has been kept in 2025 to understand what further infrastructure upgrades and reinforcements will be required to reach Phase 2 demands (additional 1,700 m3/hr from Phase 1).

2. Alternatives Considered

Numerous internal simulations were conducted to check how existing piping upgrades and station capacity increases would enable meeting Phase 1 demands. One solution involved a new station with a dedicated pipeline to the customer which was a very expensive option. Further, other solutions included station upgrades to North Walsingham station as well as significant piping upgrades to meet Phase 1 load. Essentially, simulations revealed that an upgrade of the existing piping configuration is unavoidable to sustain the increased large agricultural customer demand and as such would require significant capital investments. The Clearbeach proposal of gas supply from Maricann Station was the most practical and feasible option to meet Phase 1 load.

Alternately, Enbridge was also contacted to check for available capacity east of the customer site. Delayed response to providing an initial assessment of options results in ENGLP going with the Clearbeach proposal of providing gas supply for Phase 1 load.

3. Cost and Cost Basis

Costs have been estimated based on historical experience, costs received from Clearbeach Resource for installation plus any inflationary impacts.

Step 1: Cost Breakdown for 800 m3/hour

TYPE	ITEM	Final Units	UOM	CAPEX VALUE
PIPE	Main (P.E.)	**2,126**	meter	$113,924.48
WIRE	Tracer Wire	**2,228**	meter	$1,269.68
STATION	**CUSTOMER STATION**	**1**	station	$10,000.00
MISC	Straight T	**1**	unit	$ 89.89
MISC	Reducing Couplings	**3**	unit	$ 359.73
MISC	Poly Valve	**1**	unit	$398.00
ENGLP LABOUR	Gas Tech	**20**	hr	$1,941.40
ENGLP LABOUR	S2 Management	**32**	hr	$4,312.96
ENGLP LABOUR	GIS	**2**	hr	$187.20
ENGLP LABOUR	ENGLP QA/QC (Keith, Aylmer only)	**100**	hr	$9,500.00
AECON Main Install COST	P.E. main install (SB)	**2,025**	meter	$784,667.25
AECON Overhead	AECON Overhead	**1**	install	$867.13
AECON Other COST	Pipe Transport	**1**	project	$25,000.00
	Total			$952,517.71
	Project Contingency	10%		$95,251.77
	Total Project Costs			**$1,047,769.48**

Step 1: Cost Breakdown to reach full Phase 1 load of 1,700 m3/hour

ITEM	CAPEX VALUE	15% contingency addition

Clearbeach Resources upstream reinforcement and monitoring	$169,754	$195,217
Modifications at Maricann Station	$39,987	$45,985
4"PE Pipeline from Maricann station to Customer	$340.989	$392,137
Regulating Station at Customer	$22,516	$35,939
Total Project Costs	**$573,245**	**$669,277**

4. Timelines and Milestones

The main and service installation for 6inch is planned for January 2024. This will take approximately 4 weeks to complete.

The second step to reach Phase 1 load of 1,700 m3/hour (additional 900 m3/hour from step 1) is to complete execution by November 2024.

Lastly, a placeholder ($500k) has been kept in 2025 to understand what further infrastructure upgrades and reinforcements will be required to reach Phase 2 demands (additional 1,700 m3/hr from Phase 1).

Any engineering and procurement of future projects is be completed in advance to facilitate the construction of the capital work during the 2024 and 2025 budget year(s).

5. Execution Risks

The main risk to this project would be the weather conditions in January. Winter conditions could delay the construction timeline. The customer will have operational risk in not being able to melt snow off of their greenhouse structure, and ENGLP will lose the opportunity to make the revenue off of a large consuming customer.

6. Preliminary Execution Strategy

Once the USP is approved, ENGLP will utilize internal and external sources to plan and execute from engineering to construction. This will allow ENGLP to complete this reinforcement project while maintaining internal resources to complete other system renewal and system access projects (service additions, main additions, regulator additions etc.).

Project Name:	**System Access - 5MW Natural Gas fired Power Plant Customer Addition (Project)**		
Project Number:	N/A	**Capitalization Criteria:**	Creation/Acquisition
Project Initiator:	Mark Emmanuel	**Enterprise Project Driver :**	2. Growth/Customer Requirements
Project Manager:	Mark Emmanuel	**Primary BU:**	ENGLP – 5B
Project Sponsor(s):	Darren McCrank Director, Ontario Operations	**Filing/Regulatory Reference:**	System Access

	FUNDING BY YEAR						
	2024	**2025**	**2026**	**2027**	**2028**	**2029**	**TOTAL**
Capital Expenditure ($)			**$1,124,220**				
External Contribution ($)			**(404,705)**				
Net Capital Cost TOTAL			**$719,515**				
Capital Addition (%)			**100%**				
Operating Expenditure ($)	**0**	**0**	**0**	**0**	**0**		**0**

1. Background and Justification

Ontario is entering into a period of emerging electricity system needs driven by increasing demand. This is due to the retirement of the Pickering nuclear plant, the refurbishment of other nuclear generating units, as well as expiring contracts for existing facilities. Recognizing the necessity to address these needs in a timely, cost-effective and flexible manner, the Independent Electricity System Operator (IESO) has engaged with stakeholders in the development of a resource adequacy framework.

One of the mechanisms to support the IESO's resource adequacy initiatives is the Long-Term Request for Proposals (the "LT1 RFP"), which is intended to acquire capacity services to meet system reliability needs from new builds and eligible expansions. These include new build storage facilities, registered or able to become registered in the IESO-administered markets, larger than 1 MW and which can deliver a continuous amount of electricity to a connection point on a distribution system or transmission system for at least four consecutive hours.

In the Aylmer distribution area, CEM Engineering has applied for the development of a 5MW natural gas fired power plant to participate in the IESO's LT1 RFP process. The below forecasts for gas consumption have been provided:

Peak hourly flow – 1,130 m3/hour

Peak day flow – 18,080 m3/hour

Annual volume requirement – 1,695,000 m3/hour

The main fuel source would be grid gas from ENGLP. In the future, there is potential to run RNG through it before it goes to the grid but that is hypothetical at this point.

2. Alternatives Considered

The main fuel source would be grid gas from ENGLP. In the future, there is potential to run RNG through it before it goes to the grid but that is hypothetical at this point.

3. Scope of Recommended Option

Option 1:

- Upgrade assets in Bayham station to increase max flow from current 1,854 m3/hour to 2,100 m3/hour (Cost ~10k)
- Upgrade the current 4" piping coming out of Bayham station to 6" from Bayham station to the intersection of Talbot Line and Somers Road. Total length ~4.5 kms (Cost ~$1.3M)
- Total Cost - $1.3M; Customer Contribution - $650k

Option 2:

- Upgrade assets in Bayham station to increase max flow from current 1,854 m3/hour to 2,300 m3/hour (~25k)
- Upgrade the current 4” piping coming out of Bayham station to 6” to the intersection of Talbot Line and Best Line. Total length ~3.5 kms (Cost ~$1.1M)
- Total Cost - $1.1M; Customer Contribution - $400k

4. Cost and Cost Basis

Costs have been estimated based on historical experience, plus inflationary impacts. Please refer to Appendices Section for cost estimate breakdowns.

TYPE	ITEM	Final Units	UOM	CAPEX VALUE
PIPE	Main (P.E.)	**3,500**	meter	$ 230,442.50
WIRE	Tracer Wire	**3,850**	meter	$ 4,119.50
ENGLP LABOUR	Gas Tech	**70**	hr	$ 4,827.20
ENGLP LABOUR	S2 Management	**120**	hr	$ 16,504.80
ENGLP LABOUR	GIS	**8**	hr	$ 748.80
ENGLP LABOUR	ENGLP QA/QC	**100**	hr	$ 9,500.00
AECON Main Install COST	P.E. main install	**3,500**	meter	$ 752,500.00
AECON Overhead	AECON Overhead	**1**	install	$ 329.51
AECON Other COST	Miscellaneous	**1**	project	$ 30,000.00
	Total Project Costs			$ 1,048,972

5. Timelines and Milestones

The IESO program currently plans to announce successful projects in May 2024. If successful, the power plant would be planned on a 2-year build-out with a commissioning time frame in May of 2026.

6. Execution Risks

N/A

7. Preliminary Execution Strategy

Once the USP is approved and the project is successful in the IESO bid, ENGLP will utilize internal and external sources to plan and execute from engineering to construction. This will allow ENGLP to complete this reinforcement project while maintaining internal resources to complete other system renewal and system access projects (service additions, main additions, regulator additions etc.).

Project Name:	**System Renewal - Main Replacements (Program)**		
Project Number:	N/A	**Capitalization Criteria:**	Improvement
Project Initiator:	Mark Emmanuel	**Enterprise Project Driver :**	3. Reliability or Life Cycle Replacement
Project Manager:	Mark Emmanuel	**Primary BU:**	ENGLP – 5B
Project Sponsor(s):	Darren McCrank Director, Ontario Operations	**Filing/Regulatory Reference:**	System Renewal

FUNDING BY YEAR						
	2025	**2026**	**2027**	**2028**	**2029**	**TOTAL**
Capital Expenditure ($)	**$47,320**	**$54,660**	**$52,580**	**$62,760**	**$63,030**	**$280,350**
External Contribution ($)						
Net Capital Cost TOTAL	**$47,320**	**$54,660**	**$52,580**	**$62,760**	**$63,030**	**$280,350**
Capital Addition (%)	**100%**	**100%**	**100%**	**100%**	**100%**	
Operating Expenditure ($)	**0**	**0**	**0**	**0**	**0**	**0**

1. Background and Justification

The Main Replacements program accounts for the replacement of pipe assessed to be at the end of the useful service life. The estimated annual capital spend is estimated based on management judgement and average historical spending.

The gas main replacements will be contracted out to our third-party Alliance Contractor (Aecon Utilities). Installation labor and contractor cost estimates included in the estimated program are based on our existing Master Service Agreement rates with Aecon Utilities with inflationary measures added year by year. ENGLP internal staff will complete any tie-ins to the system.

Individual projects for the purposes of mains replacement are planned based on operational risk. Projects may be added, deferred and/or reprioritized within the overall program, and approved program budget, as circumstances dictate.

2. Alternatives Considered

N/A

3. Scope of Recommended Option

The Main Replacements program accounts for the replacement of pipe assessed to be at the end of the useful service life. The estimated annual capital spend is estimated based on management judgement and average historical spending.

Provided the system has the capacity to complete the main replacements, spending is generally non-discretionary. Program spending for the purposes of main replacements is required to maintain system integrity and mitigate risk, helping to ensure the utility can continue to provide safe and reliable natural gas service. This spending is generally discretionary and projects may be added, deferred and/or reprioritized within the overall program, and approved program budget, as circumstances dictate.

4. Cost and Cost Basis

Costs have been estimated based on historical experience, current Master Service Agreement rates with Aecon Utilities, plus inflationary impacts. Costing for the Mains Replacements program has been evenly spread over the USP period to ensure ENGLP has the resources and materials to ensure project completion on time.

5. Timelines and Milestones

The Main Renewal program are slated to be completed within the System Renewal annual program 2025-2029 budget years. The procurement of these projects as per need basis during the construction of these capital projects.

6. Execution Risks

Program spending for the purposes of main replacements are required to maintain system integrity and mitigate risk, helping to ensure the utility can continue to provide safe and reliable natural gas service. This spending is generally discretionary and projects may be added, deferred and/or reprioritized within the overall program, and approved program budget, as circumstances dictate. Overall, there are no risks identified that would have a potential impact to project cost, schedule and performance criteria.

7. Preliminary Execution Strategy

Develop a list of main replacement projects to be completed in the budget year with plenty of lead time. Once the USP is approved, ENGLP will utilize internal and external sources for each budget year to complete the projects from planning and procurement to execution. This will allow ENGLP to complete main replacement projects while maintaining internal resources to complete other system renewal and system access projects (service additions, meter additions, regulator additions etc.). Any approvals (MTO for example) will be completed during the engineering and design process of the main addition projects.

Project Name:	System Renewal - Service Replacements (Program)		
Project Number:	N/A	Capitalization Criteria:	Improvement
Project Initiator:	Mark Emmanuel	Enterprise Project Driver :	3. Reliability or Life Cycle Replacement
Project Manager:	Mark Emmanuel	Primary BU:	ENGLP – 5B
Project Sponsor(s):	Darren McCrank Director, Ontario Operations	Filing/Regulatory Reference:	System Access

FUNDING BY YEAR						
	2025	2026	2027	2028	2029	TOTAL
Capital Expenditure ($)	$79,930	$78,910	$66,820	$72,010	$77,280	$374,950
External Contribution ($)	($3,500)	($3,500)	($3,500)	($3,500)	($3,500)	($17,500)
Net Capital Cost TOTAL	$76,430	$75,410	$63,320	$68,510	$73,780	$357,450
Capital Addition (%)	100%	100%	100%	100%	100%	
Operating Expenditure ($)	0	0	0	0	0	0

1. Background and Justification

The Service Replacements program accounts for the lifecycle replacement of existing services, although this represents a small fraction of overall program costs. Program costs are partially funded by a customer contribution in aid of construction in the form of a connection fee

Typical service line (½”) replacements using a trenchless plow and small excavator are conducted by ENGLP internal operations. Larger service line replacements, including directional drilling, are contracted out to our third-party Alliance Contractor (Aecon Utilities). Installation labor and contractor cost estimates included in the estimated program are based on our existing Master Service Agreement rates with Aecon Utilities with inflationary measures added year by year.

2. Alternatives Considered

N/A

3. Scope of Recommended Option

The Service Replacements program accounts for the lifecycle replacement of existing services, although this represents a small fraction of overall program costs. Program costs are partially funded by a customer contribution in aid of construction in the form of a connection fee

Program spending for the purposes of service connections are required to maintain system integrity and mitigate risk, helping to ensure the utility can continue to provide safe and reliable natural gas service. This spending is generally discretionary and projects may be added, deferred and/or reprioritized within the overall program, and approved program budget, as circumstances dictate.

4. Cost and Cost Basis

Costs have been estimated based on historical experience, current Master Service Agreement rates with Aecon Utilities, plus inflationary impacts. Costing for the Service Replacements program have been evenly spread over the USP period to ensure ENGLP has the resources and materials to ensure project completion on time.

5. Timelines and Milestones

The Service Replacements program are slated to be completed within the System Access annual program 2025-2029 budget years.

6. Execution Risks

This program accounts for the costs to replace existing services and, as such, spending under the program is generally non-discretionary. Overall, there are no risks identified that would have a potential impact to project cost, schedule and performance criteria.

7. Preliminary Execution Strategy

Once the USP is approved, ENGLP will utilize internal and external sources for each budget year to complete the projects from engineering to construction. This will allow ENGLP to complete service replacements while maintaining internal resources to complete other system renewal and system access projects (service additions, meter additions, regulator additions etc.).

Project Name:	**System Renewal - ENGLP Regulating Station Rehab and Maintenance (Program)**		
Project Number:	N/A	**Capitalization Criteria:**	Improvement
Project Initiator:	Mark Emmanuel	**Enterprise Project Driver :**	3. Reliability or Life Cycle Replacement
Project Manager:	Mark Emmanuel	**Primary BU:**	ENGLP – 5B
Project Sponsor(s):	Darren McCrank Director, Ontario Operations	**Filing/Regulatory Reference:**	System Renewal

FUNDING BY YEAR						
	2025	**2026**	**2027**	**2028**	**2029**	**TOTAL**
Capital Expenditure ($)	**$82,830**	**$194,270**	**$211,250**	**$212,260**	**$209,180**	**$909,790**
External Contribution ($)						
Net Capital Cost TOTAL	**$82,830**	**$194,270**	**$211,250**	**$212,260**	**$209,180**	**$909,790**
Capital Addition (%)	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**
Operating Expenditure ($)	**0**	**0**	**0**	**0**	**0**	**0**

1. Background and Justification

This program accounts for the replacement/upgrade of pressure regulating stations. The capital work required at the pressure regulating stations has various drivers including safety and reliability, security, regulatory compliance, capacity, condition (signs of corrosion/pitting), age, and obsolescence. The proposed replacements and upgrades include a wide range of capital improvements extending from new installations to specific equipment component replacements and upgrades. Although the majority of the costs for station capital activities relates to the need for replacement of all or part of the stations, in some case the capital requirements also address the need for capacity related modifications.

The estimated program costs account for station replacement, labor, fencing, sandblasting/painting and contingency costs within the years of 2025, 2026, 2027, 2028 and 2029.

2. Alternatives Considered

There are no alternatives to be considered for the ENGLP Regulating Station Rehab Program. Spending under this program is non-discretionary.

3. Scope of Recommended Option

Program spending for the purposes regulating station rehab are required to maintain system integrity and mitigate risk, helping to ensure the utility can continue to provide safe and reliable natural gas service. This spending is generally non-discretionary and projects may be added, deferred and/or reprioritized within the overall program, and approved program budget, as circumstances dictate.

The forecast annual capital spend is based on management judgement looking at the age and status of each station as well as historical spend based on the replacement of one regulating station per year. In 2025, the plan is to replace the Teall Hill pressure regulating station. The costs associated with this upgrade include material and fabrication of the station, site preparation and station supports, bringing station to site and completing a partial installation, inlet riser installation and ENGLP construction crew carrying out tie-in activities to pipeline after partial installation complete. In 2026, the plan is to replace and relocate the Belmont/Nilestown station due to signs of corrosion/pitting on risers. Between the years 2027-2029, further regulating station rehab work is expected to be completed based on factors such as safety and reliability, security, regulatory compliance, capacity, condition (signs of corrosion/pitting), age, and obsolescence

4. Cost and Cost Basis

The estimated program costs account for station replacement, labor, fencing, sandblasting/painting and contingency costs within the years of 2025, 2026, 2027, 2028 and 2029.

5. Timelines and Milestones

The Regulating Station rehab program is slated to be completed within the System Access annual program 2025-2029 budget years. The engineering and procurement of these projects is be completed in advance to facilitate the construction of the capital work.

6. Execution Risks

The ENGLP Regulating Station rehab program ensures the efficient and reliable operation of meter and pressure regulating stations which is critical for ENGLP Natural Gas to maintain safe and reliable distribution of natural gas to its customers. Pressure regulating stations are upgraded on an as-required basis and periodically assessed to identify any required upgrades to maintain safe and reliable function. Overall, there are no risks identified that would have a potential impact to project cost, schedule and performance criteria.

7. Preliminary Execution Strategy

The yearly program will be executed with external contractor (possibly Lakeside) for the regulating station fabrication, bringing station to site and completing a partial installation, inlet riser installation as well as ENGLP internal construction crew to carry out tie-in activities to the pipeline after partial installation is complete.

Project Name:	System Renewal - Meter Replacements (Program)		
Project Number:	N/A	Capitalization Criteria:	Compliance
Project Initiator:	Mark Emmanuel	Enterprise Project Driver :	3. Reliability or Life Cycle Replacement
Project Manager:	Mark Emmanuel	Primary BU:	ENGLP – 5B
Project Sponsor(s):	Darren McCrank Director, Ontario Operations	Filing/Regulatory Reference:	System Renewal

FUNDING BY YEAR						
	2025	2026	2027	2028	2029	TOTAL
Capital Expenditure ($)	$820,990	$799,260	$446,050	$437,450	$99,740	$2,603,490
External Contribution ($)						
Net Capital Cost TOTAL	$820,990	$799,260	$446,050	$437,450	$99,740	$2,603,490
Capital Addition (%)	100%	100%	100%	100%	100%	
Operating Expenditure ($)	0	0	0	0	0	0

1. Background and Justification

The Meter Replacement program accounts for the lifecycle replacement or refurbishment of meters on existing services. Measurement Canada approves natural gas meters to be used for billing purposes and establishes the requirements related to service life. A new meter is verified for accuracy and sealed by an accredited body prior to being placed into service. Upon expiry of the approved verification period, the meter must be removed from service or re-verified directly or through a sampling program.

Given the relatively high cost of re-verification (e.g. labor, shipping, verification by an accredited 3rd-party meter shop) in comparison to the relatively low cost of residential meters, ENGLP currently replaces residential meters (sizes 250 and 425 SCFH) when the initial verification period expires. For more the larger, more costly commercial meters, it is often economical to send them to an accredited meter shop to be refurbished, re-verified, and returned to service one or more times.

Meter costs are based on updated pricing received from vendors. Sizes 250, 425 and 630 SCFH come from Honeywell (Elster) and all the larger meters come from GE (Dresser) and Romet. The OPCO regulators manufacturer is Pietro Fiorentini. The estimated program costs are based on a count of meters within inventory with seals set to expire within the years of 2025, 2026, 2027, 2028 and 2029.

2. Alternatives Considered

ENGLP is required to ensure that meters are removed from service or re-verified and sealed upon expiry of the approved verification period, as per the requirements of Measurement Canada, and comply with meter accuracy obligations prescribed under the Electricity and Gas Inspection Act. Spending under this program is non-discretionary.

3. Scope of Recommended Option

The Meter Replacement program accounts for the lifecycle replacement or refurbishment of meters on existing services. Measurement Canada approves natural gas meters to be used for billing purposes and establishes the requirements related to service life. A new meter is verified for accuracy and sealed by an accredited body prior to being placed into service. Upon expiry of the approved verification period, the meter must be removed from service or re-verified directly or through a sampling program.

Program spending for the purposes of meter replacements is required to maintain system integrity and mitigate risk, helping to ensure the utility can continue to provide safe and reliable natural gas service. This spending is generally discretionary and projects may be added, deferred and/or reprioritized within the overall program, and approved program budget, as circumstances dictate.

4. Cost and Cost Basis

Costs have been estimated based on historical experience, plus inflationary impacts. Costing for the Meter Replacement program is based upon meter seal expiry date as per Measurement Canada requirements for the years 2025, 2026, 2027, 2028 and 2029.

5. Timelines and Milestones

The Meter Replacement program is slated to be completed within the System Renewal annual program 2025-2029 budget years. The engineering and procurement of these projects is be completed in advance to facilitate the construction of the capital work.

6. Execution Risks

Program spending for the purposes of meter replacements are required to maintain system integrity and mitigate risk, helping to ensure the utility can continue to provide safe and reliable natural gas service. This spending is generally non-discretionary and projects may be added, deferred and/or reprioritized within the overall program, and approved program budget, as circumstances dictate. Overall, there are no risks identified that would have a potential impact to project cost, schedule and performance criteria.

7. Preliminary Execution Strategy

Develop a list of meter replacements and refurbishments to be completed in the budget year with plenty of lead time. Once the USP is approved, ENGLP will utilize internal and external sources for each budget year to complete the projects from engineering to construction. This will allow ENGLP to complete meter replacements while maintaining internal resources to complete other system renewal and system access projects (service additions, main additions, regulator additions etc.).

Project Name:	**System Renewal - Regulator Replacements (Program)**		
Project Number:	N/A	**Capitalization Criteria:**	Compliance
Project Initiator:	Mark Emmanuel	**Enterprise Project Driver :**	3. Reliability or Life Cycle Replacement
Project Manager:	Mark Emmanuel	**Primary BU:**	ENGLP – 5B
Project Sponsor(s):	Darren McCrank Director, Ontario Operations	**Filing/Regulatory Reference:**	System Renewal

FUNDING BY YEAR						
	2025	**2026**	**2027**	**2028**	**2029**	**TOTAL**
Capital Expenditure ($)	**$128,580**	**$140,020**	**$135,320**	**$145,210**	**$117,560**	**$666,690**
External Contribution ($)						
Net Capital Cost TOTAL	**$128,580**	**$140,020**	**$135,320**	**$145,210**	**$117,560**	**$666,690**
Capital Addition (%)	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**
Operating Expenditure ($)	**0**	**0**	**0**	**0**	**0**	**0**

1. Background and Justification

The Regulator Replacement program accounts for the lifecycle replacement of existing regulators within the natural gas distribution system. Pressure regulators and relief valves are used to control pressures within the distribution system and on residential, commercial and industrial service connections, and prevent overpressure and damage to pipelines and downstream equipment.

Regulator replacement costs are based on updated pricing received from vendors. Regarding regulators for residential services, this program accounts for the lifecycle replacement of those on existing services only. The cost of new regulator additions is captured separately in the annual Regulator Additions program.

2. Alternatives Considered

As control and process safety devices, pressure regulators and relief valves must be regularly maintained and replaced to ensure they are in working order to prevent the overpressure and failure of pipelines and downstream equipment.

3. Scope of Recommended Option

The Regulator Replacement program accounts for the lifecycle replacement of existing regulators within the natural gas distribution system. Pressure regulators and relief valves are used to control pressures within the distribution system and on residential, commercial and industrial service connections, and prevent overpressure and damage to pipelines and downstream equipment.

Regulator replacement costs are based on updated pricing received from vendors. Regarding regulators for residential services, this program accounts for the lifecycle replacement of those on existing services only. The cost of new regulator additions is captured separately in the annual Regulator Additions program.

Program spending for the purposes of regulator replacements are required to maintain system integrity and mitigate risk, helping to ensure the utility can continue to provide safe and reliable natural gas service. This spending is generally non-discretionary and projects may be added, deferred and/or reprioritized within the overall program, and approved program budget, as circumstances dictate.

4. Cost and Cost Basis

Costs have been estimated based on historical experience, plus inflationary impacts The estimated program costs are based on an average count of 200 regulator replacements within the years of 2025, 2026, 2027, 2028 and 2029.

5. Timelines and Milestones

The Regulator Replacements program is slated to be completed within the System Renewal annual program 2025-2029 budget years. The engineering and procurement of these projects is be completed in advance to facilitate the construction of the capital work.

6. Execution Risks

Program spending for the purposes of regulator replacements are required to maintain system integrity and mitigate risk, helping to ensure the utility can continue to provide safe and reliable natural gas service. This spending is generally non-discretionary and projects may be added, deferred and/or reprioritized within the overall program, and approved program budget, as circumstances dictate. Overall, there are no risks identified that would have a potential impact to project cost, schedule and performance criteria.

7. Preliminary Execution Strategy

Develop a list of regulator replacements completed in the budget year with plenty of lead time. Once the USP is approved, ENGLP will utilize internal and external sources for each budget year to complete the projects from engineering to construction. This will allow ENGLP to complete regulator replacements while maintaining internal resources to complete other system renewal and system access projects (service additions and replacements, main additions and replacements, meter additions and replacements etc.).

Project Name:	System Renewal – IGPC Pipeline Asset Management (Project)		
Project Number:	N/A	Capitalization Criteria:	Improvement
Project Initiator:	Mark Emmanuel	Enterprise Project Driver :	3. Reliability or Life Cycle Replacement
Project Manager:	Mark Emmanuel	Primary BU:	ENGLP – 5B
Project Sponsor(s):	Darren McCrank Director, Ontario Operations	Filing/Regulatory Reference:	System Service

FUNDING BY YEAR						
	2025	2026	2027	2028	2029	TOTAL
Capital Expenditure ($)	$300,000	$300,000				$600,000
External Contribution ($)						
Net Capital Cost TOTAL						
Capital Addition (%)	100%	100%				100%
Operating Expenditure ($)	0	0	0	0	0	0

1. Background and Justification

ENGLP owns and operates a 30km 6 inch NPS steel pipeline that serves a single customer, IGPC's ethanol plant in Aylmer. This pipeline was constructed in 2007 by NRG, and has a history of integrity issues associated with the last 400m section. In 2016, NRG experienced a leak on this section raising concerns with the original installation method and cathodic protection used to prevent corrosion in the 400m section. In October 2020, ENGLP experienced another leak on this section that needed to be cut out and replaced. In September 2022, a Magnetic Flux Leakage tool (MFL) was run through the pipeline to detect metal loss, corrosion and pitting in the pipeline. This was a key component of the integrity management program for the pipeline as per CSA Z662 Code. The MFL tool results determined that 76 metal loss/corrosion features (Internal and External) exist on the IGPC pipe. The majority of the features identified along the 30km stretch are minor (20-50% metal loss) in nature and from an integrity management perspective, it was assessed that the pipeline could be operated safely and reliably until further assessments and inspection activities take place. The results also confirmed that there are 16 minor and 1 major – 78% metal loss features on this 400m section of pipe.

In April 2024, during IGPC's planned annual 2 day shutdown, ENGLP, working with its alliance partner, Aecon, executed on the cut out and replacement of the 78% metal loss feature. From an integrity and reliability perspective short/mid-term, it was strongly recommended that the section of 8 meters of 6" STL pipe with a Phase 1 feature be cut-out and replaced.

The following site activities took place during the cut out and replace along with Mobilization and De-Mobilization:

i. Excavation in shoulder of the road.
ii. Installation of trench boxes
iii. Cut out and replace of the Phase 1 feature with the highest pipe metal loss as indicated by the MFL tool data.
iv. Perform NDE testing to ensure the integrity of welded joints
v. Restoration work of all excavated pits and roadways in the section on Progress Drive.

The capital project placeholders in 2025 and 2026 include plans to conduct integrity digs on the other significant (>50% metal loss) features on the 400m section of pipe. ENGLP operations and engineering will explore using less costly options to repair individual features, including the use of composite sleeves that can structurally reinforce or permanently restore external anomalies. Sleeve repairs can be done on metal loss features less than 80%.

2. Alternatives Considered

The alternate option was to replace the entire 400m section of pipe. The assessment was that it would be more financially prudent to replace this entire section of pipe rather than dealing with the individual metal loss features separately. The estimated cost the replacement project was close to $1.5M. This was assessed by regulatory to determine the impact to the dedicated IGPC rates. It was determined that the cost of this project was entirely out of sync with the existing rate base value of this pipeline which is approximately $3.0 to $3.5M after 14 years of depreciation. The impact of this project could be up to a 25% increase to existing rates paid by the customer.

The impact of this cost was deemed to be unacceptable making this option to replace this 400m section of the pipeline unviable. Alternative options were then explored in order to manage the integrity risk. Operations and engineering began to explore less costly options to repair individual features, including the use of composite sleeves that can structurally reinforce or permanently restore external anomalies for metal loss features less than 80%.

3. Cost and Cost Basis (Per Integrity Dig - 2025)

Project Cost Breakdown	New Project - no Prior Year Costs	2024	2025	2026 and beyond	Total Project Costs
Internal Costs (Labour and Burden)		-	5,526	-	**5,526**
External Costs (Contractors & Consultants)		-	280,000	-	**280,000**
Vehicle/Equipment Costs		-	-	-	**-**
Contingency (Total Project = 0%)		-	-	-	**-**
Capital Overhead		-	3,865	-	**3,865**
IDC		-	-	-	**-**
Other Costs - Inflation		-	10,080	-	**10,080**
Total Project Cost before contributions	**-**	**-**	**299,471**	**-**	**299,471**
Contributions	-	-	-	-	**-**
Total Project Cost net of contributions	**-**	**-**	**299,471**	**-**	**299,471**

4. Timelines and Milestones

The obligations for cut out and replace work or composite sleeve repairs will take place during IGPC's planned shutdowns in April or September. The engineering and procurement of these projects is be completed in advance to facilitate the construction of the capital work during the 2024, 2025 and 2026 budget year(s). The estimates assume work for 3 days a week, 10 hours per day.

5. Execution Risks

The pipe cut out and replace work involves the excavation in shoulder of the road, installation of trench boxes to safely cut out and replace 8 meters of 6" Steel pipe, this also includes cost of asphalt patch, concrete curb and NDE of the welded pipe, as well as the restoration work of all excavated pits and roadways in the section on Progress Drive in Aylmer.

System Service reinforcement project spending are required to maintain system integrity and mitigate risk, helping to ensure the utility can continue to provide safe and reliable natural gas service. This spending is generally non-discretionary, and approved program budget, as circumstances dictate. Overall, there are no risks identified that would have a potential impact to project cost, schedule and performance criteria.

6. Preliminary Execution Strategy

Once the USP is approved, ENGLP will utilize internal and external sources to plan and execute from engineering to construction. This will allow ENGLP to complete this reinforcement project while maintaining internal resources to complete other system renewal and system access projects (service additions, main additions, regulator additions etc.).

Project Name:	System Service - SCADA System Upgrade (Program)		
Project Number:	N/A	Capitalization Criteria:	Improvement
Project Initiator:	Mark Emmanuel	Enterprise Project Driver :	3. Reliability or Life Cycle Replacement
Project Manager:	Mark Emmanuel	Primary BU:	ENGLP – 5B
Project Sponsor(s):	Darren McCrank Director, Ontario Operations	Filing/Regulatory Reference:	System Service

FUNDING BY YEAR						
	2025	2026	2027	2028	2029	TOTAL
Capital Expenditure ($)	$35,050	$39,950	$43,030	$46,540	$50,050	$214,620
External Contribution ($)						
Net Capital Cost TOTAL	$35,050	$39,950	$43,030	$46,540	$50,050	$214,620
Capital Addition (%)	100%	100%	100%	100%	100%	100%
Operating Expenditure ($)	0	0	0	0	0	0

1. Background and Justification

System service investments are modifications to ENGLP's natural gas distribution system to ensure the distribution system continues to meet operational objectives while addressing anticipated future customer natural gas service requirement. As part of ENGLP's due diligence, existing field instrumentation and supervisory control and data acquisition ("SCADA") system requires modernization.

The current system used to monitor and control pressures and flows within the distribution system needs to be aligned with current industry accepted practices to ensure reliable operation of the utility. The SCADA System Upgrade program spending needs to maintain the functionality of the SCADA system to help ENGLP gain efficiencies and to keep the technology stack current.

Continued development of SCADA systems is required to provide timely, detailed and accurate information to operations staff. Through this program, ENGLP intends to upgrade the field instrumentation and SCADA system to allow field measurements to transfer in real-time to a central SCADA computer, creating a single operator interface to monitor the system locally or remotely, view and change set-points, and track and trend historical data. Most importantly, this will allow pressures and flows to monitored and alarms to be generated and dialed-out to operating staff in the event of a deviation.

2. Alternatives Considered

Without a SCADA system in place to provide monitoring and alerting we remain open to the following risks:

- No visibility into system operation
- No alerting on failure conditions
- Severe operator fatigue
- Loss of compliance data
- Degraded system performance
- Unknown levels of line loss
- Inaccurate reliability metrics
- Reliance on customers to report problems

3. Scope of Recommended Option

The existing SCADA system requires operating staff to manually poll field instrumentation, (pressures and temperatures) from a cellular phone or a single desktop computer located in the Aylmer office and relies on the diligence of operating staff to periodically dial-in and check the field devices during times of peak demand and make changes to set-points as required. Additionally, the current infrastructure does not allow for alarms to be generated and an alert to be sent to operating staff should a measured variable be outside the acceptable range.

Under this program, ENGLP intends to upgrade the field instrumentation and SCADA system to allow field measurements to transfer in real-time to a central SCADA computer, creating a single operator interface to monitor the system locally or remotely, view and change set-points, and track and trend historical data. Most importantly, this will allow pressures and flows to monitored and alarms to be generated and dialed-out to operating staff in the event of a deviation.

The annual program will entail solar panel upgrades, modem upgrades and possibly instrumentation upgrades depending on the condition of the existing equipment and the plan is to continue adding over time until they are all online.

4. Cost and Cost Basis

Costs within the years of 2025, 2026, 2027, 2028 and 2029 have been estimated based on historical experience, plus inflationary impacts.

5. Timelines and Milestones

The SCADA System Upgrade program is slated to be completed within the System Service annual program 2025-2029 budget years.

6. Execution Risks

Program spending for the purposes of SCADA upgrades are required to maintain system integrity and mitigate risk, helping to ensure the utility can continue to provide safe and reliable natural gas service. This spending is generally non-discretionary. Overall, there are no risks identified that would have a potential impact to project cost, schedule and performance criteria.

7. Preliminary Execution Strategy

N/A

Project Name:	System Service - Port Burwell Low Pressure Reinforcement (Project)		
Project Number:	N/A	Capitalization Criteria:	Improvement
Project Initiator:	Mark Emmanuel	Enterprise Project Driver :	3. Reliability or Life Cycle Replacement
Project Manager:	Mark Emmanuel	Primary BU:	ENGLP – 5B
Project Sponsor(s):	Darren McCrank Director, Ontario Operations	Filing/Regulatory Reference:	System Service

FUNDING BY YEAR						
	2025	2026	2027	2028	2029	TOTAL
Capital Expenditure ($)	$415,500					$415,500
External Contribution ($)						
Net Capital Cost TOTAL	$415,500					$415,500
Capital Addition (%)	100%	100%	100%	100%	100%	100%
Operating Expenditure ($)	0	0	0	0	0	0

1. Background and Justification

Historically, the southern and southeastern portion of the Aylmer distribution system has been a troublesome area in terms of pressure concerns during low temperature days. In recent years, the addition of the Lakeview Station supply has helped. However, Eden Station and North Walsingham Station maintain their status of some of the weaker station injecting gas into the Aylmer system due to their location on the Enbridge supply. During wintertime, the line feeding Eden and North Walsingham becomes strained and those station see a decrease anywhere from 25%-50% of their throughput – despite the stations needing volume to supply ENGLP customers during those times. To continue to ensure safe and reliable service to existing customers in the area, and support ongoing development and access to natural gas, reinforcement of the system is required.

Port Burwell, a small community on the lakeshore, operates as a 30psig system. There are two 2inch gas lines that feed the town. Both regulator stations are located in excess of 1km away from the town center. This run of relatively small pipe causes a substantial pressure drop, in which gas reaching the town is around 10psig or less. That is a 20psi drop. In the previous (2018) Integrity Study and Cost of Service application submission it was determined that if growth is substantial in Port Burwell over the next few years and demand spikes, the pressure Port Burwell sees will drop even lower. Since this was not a high priority needing immediate reinforcement in 2018, no CAPEX was performed. However, in recent years (2022 and 2023 Dec/Jan) low pressures have been noted in Port Burwell and south east of the system causing outages during peak winter. Pressures in Port Burwell were below 5 psig and the utility was at risk of unplanned customer outages. The situation will only get worse as demands increase and production from the connected wells continues to decline.

The recommended reinforcement option to alleviate low pressures in the area involves:

a) Relocating the current Port Burwell Teall Hill regulator station ~2.5kms from its current location down south and
b) Upgrading the existing ~2.5kms of 2inch pipe to 4inch that feeds Port Burwell along Plank Road.

The relocated Port Burwell Teall Hill regulator station will knock the existing 80psi inlet pressure to 30psi outlet in order to feed the community of Port Burwell.

2. Alternatives Considered

In recent years, during periods of low temperatures and resulting record high natural gas demands, system pressures in the community of Port Burwell were well below system design and the utility was and continues to be at risk of unplanned customer outages. The situation will only get worse as demands increase and production from the connected wells continues to decline. To continue to ensure safe and reliable service to existing customers and support ongoing development in the area, reinforcement of the system is required and spending under this program is non-discretionary.

As an alternative, ENGLP did review the option of the addition of trailered compressed natural gas (CNG) on-system storage in the south of the system, to be used to supplement the existing gas supply during peak demands. The capital cost of this option is significantly higher than the proposed solution. This approach would also be expected to have higher ongoing operating and maintenance costs. The reliability of supply would also have to be properly addressed, as peak demands occur in the winter when road conditions can be poor, potentially making it difficult to move CNG trailers when required. As such, this alternative was rejected.

3. Scope of Recommended Option

ENGLP contracted Cornerstone to conduct an engineering and integrity study to review the current constraints within the Aylmer utility natural gas distribution system. Cornerstone was asked to:

- Review the distribution system and, given current peak system demands, identify system constraints that are likely to lead to unacceptable low pressure conditions;
- Given forecasted growth, identify system constraints that are likely to lead to unacceptable low pressure conditions through 2029; and
- Identify and evaluate options to address the system constraints and resolve the unacceptable low pressure conditions identified.

The study identified low pressure problematic issues generally in the southern extents of the system, in particular the community of Port Burwell, confirming recent operating history. Port Burwell is fed by two independent 2inch gas mains, one feeding each side of Big Otter Creek. The system model typically does not include mains downstream of district regulators, but these two mains are downstream and operate at 30psig and were included in the model. When the peak town loads are modeled as aggregate loads located at the southernmost point of each town subsystem (east and west sides), inadequate pressure results.

The recommended reinforcement option to alleviate low pressures in the area involves:

a) Relocating the current Port Burwell Teall Hill regulator station ~2.5kms from its current location down south and
b) Upgrading the existing ~2.5kms of 2inch pipe to 4inch that feeds Port Burwell along Plank Road.

The relocated Port Burwell Teall Hill regulator station will knock the existing 80psi inlet pressure to 30psi outlet in order to feed the community of Port Burwell.

4. Cost and Cost Basis

Costs have been estimated based on historical experience, plus inflationary impacts.

Project Cost Breakdown	New Project - no Prior Year Costs	2025	2026	2027 and beyond	Total Project Costs
Internal Costs (Labour and Burden)		8,240	-	-	**8,240**
External Costs (Contractors & Consultants)		365,000	-	-	**365,000**
Vehicle/Equipment Costs		-	-	-	-
Contingency (Total Project = 9.6%)		36,500	-	-	**36,500**
Capital Overhead		5,760	-	-	**5,760**
IDC		-	-	-	-
Other Costs - Inflation		-	-	-	-
Total Project Cost before contributions	**-**	**415,500**	**-**	**-**	**415,500**
Contributions	-	-	-	-	-
Total Project Cost net of contributions	**-**	**415,500**	**-**	**-**	**415,500**

5. Timelines and Milestones

The engineering and procurement of these projects is be completed in advance to facilitate the construction of the capital work during the 2025 budget year.

6. Execution Risks

System Service reinforcement project spending are required to maintain system integrity and mitigate risk, helping to ensure the utility can continue to provide safe and reliable natural gas service. This spending is generally non-discretionary, and approved program budget, as circumstances dictate. Overall, there are no risks identified that would have a potential impact to project cost, schedule and performance criteria.

7. Preliminary Execution Strategy

Once the USP is approved, ENGLP will utilize internal and external sources to plan and execute from engineering to construction. This will allow ENGLP to complete this reinforcement project while maintaining internal resources to complete other system renewal and system access projects (service additions, main additions, regulator additions etc.).

Project Name:	System Service - South Belmont Pipe Addition (Project)		
Project Number:	N/A	Capitalization Criteria:	Improvement
Project Initiator:	Mark Emmanuel	Enterprise Project Driver :	3. Reliability or Life Cycle Replacement
Project Manager:	Mark Emmanuel	Primary BU:	ENGLP – 5B
Project Sponsor(s):	Darren McCrank Director, Ontario Operations	Filing/Regulatory Reference:	System Service

FUNDING BY YEAR						
	2025	2026	2027	2028	2029	TOTAL
Capital Expenditure ($)			$362,000	$362,000		$724,000
External Contribution ($)						
Net Capital Cost TOTAL						$724,000
Capital Addition (%)	100%	100%	100%	100%	100%	100%
Operating Expenditure ($)	0	0	0	0	0	0

1. Background and Justification

Belmont is currently supplied by two mains/streams – the northern part of the town is fed by the Nilestown station while the southern Belmont receives gas from both the Harrietsville and Dorchester stations. Each stream goes through a district regulation station set to 30 psi. However, those regulating stations do not have metering capacity currently. Thus, it is impossible to know how much help may be received by the northern and the southern areas from each other to meet the whole town's demand.

Cornerstone performed system integrity simulations for two different load cases: January peak flows/loads and fall peak flows/load for 2023 and 2028 growth forecast. Simulation of the northern Belmont stream revealed healthy supply which should be capable of delivering at least 50% more flow compared to the 2023 level with no system pressure issues anticipated. Simulation of the southern stream suggests possible problems with the system pressure with the existing 3" pipe from the intersection of Yorke Line and Elgin Road toward Belmont South station. The 3” main going toward South Belmont along Yorke Street has insufficient pressure if the January 2028 peak flow were combined with all the interruptible customers’ full consumption. Same extreme conditions indicate possible pressure issue in the 4” main feeding the Aylmer Beach Street district regulator station.

Southern Belmont area needs reinforcement to improve piping capacity. The piping segment comprises of two sections – the one on Yorke Line close to Belmont South station approximately 3.7kms in hydraulic length and another one on Yorke Line between the intersections of Imperial Road and Dorchester Road approximately 3.9kms in length.

The recommended option to improve pressures involves installing a new ~4kms 4inch pipe along Wilson Road and north on Belmont Road to alleviate the congestion at central Aylmer district and low pressure in South Belmont. Simulation results suggested that a new 4inch main line not only resolved the South Belmont area problem but also improves pressure distribution at Aylmer and eastern central districts.

ENGLP will continue to track actual flows into the southern area of Belmont and if less than assumed in the model, then the problem may not materialize. Alternately (discussed in next section), the Yorke Line main close to Belmont South (~3.7kms) will need to be upgraded to 4inch to resolve the low pressure issue.

2. Alternatives Considered

The piping segment comprises of two sections – the one on Yorke Line close to Belmont South station approximately 3.7kms in hydraulic length and another one on Yorke Line between the intersections of Imperial Road and Dorchester Road approximately 3.9kms in length. The Yorke Line main close to Belmont South will need to be upgraded to 4inch to resolve the low pressure issue.

3. Scope of Recommended Option

ENGLP contracted Cornerstone to conduct an engineering and integrity study to review the current constraints within the Aylmer utility natural gas distribution system. Cornerstone was asked to:

- Review the distribution system and, given current peak system demands, identify system constraints that are likely to lead to unacceptable low pressure conditions;

- Given forecasted growth, identify system constraints that are likely to lead to unacceptable low pressure conditions through 2029; and
- Identify and evaluate options to address the system constraints and resolve the unacceptable low pressure conditions identified.

The study identified possible problems with the system pressure with the existing 3" pipe from the intersection of Yorke Line and Elgin Road toward Belmont South station. The 3" main going toward South Belmont along Yorke Street has insufficient pressure if the January 2028 peak flow were combined with all the interruptible customers' full consumption. Same extreme conditions indicate possible pressure issue in the 4" main feeding the Aylmer Beach Street district regulator station.

The recommended option to improve pressures involves installing a new ~4kms 4inch pipe along Wilson Road and north on Belmont Road to alleviate the congestion at central Aylmer district and low pressure in South Belmont. Simulation results suggested that a new 4inch main line not only resolved the South Belmont area problem but also improves pressure distribution at Aylmer and eastern central districts.

4. Cost and Cost Basis

Costs have been estimated based on historical experience, plus inflationary impacts.

Project Cost Breakdown	New Project - no Prior Year Costs	2027	2028	Total Project Costs
Internal Costs (Labour and Burden)		4,120	4,120	**8,240**
External Costs (Contractors & Consultants)		323,500	323,500	**647,000**
Vehicle/Equipment Costs		-	-	**-**
Contingency (Total Project = 9.8%)		32,350	32,350	**64,700**
Capital Overhead		2,880	2,880	**5,760**
IDC		-	-	**-**
Other Costs - Inflation		-	-	**-**
Total Project Cost before contributions	**-**		**-**	**725,700**
Contributions	-	-	-	-
Total Project Cost net of contributions	**-**	**362,850**	**362,850**	**725,700**

5. Timelines and Milestones

The engineering and procurement of these projects is be completed in advance to facilitate the construction of the capital work during the 2028 and 2028 budget year(s).

6. Execution Risks

System Service reinforcement project spending are required to maintain system integrity and mitigate risk, helping to ensure the utility can continue to provide safe and reliable natural gas service. This spending is generally non-discretionary, and approved program budget, as circumstances dictate. Overall, there are no risks identified that would have a potential impact to project cost, schedule and performance criteria.

7. Preliminary Execution Strategy

Once the USP is approved, ENGLP will utilize internal and external sources to plan and execute from engineering to construction. This will allow ENGLP to complete this reinforcement project while maintaining internal resources to complete other system renewal and system access projects (service additions, main additions, regulator additions etc.).

Project Name:	General Plant - Fleet Vehicle Replacement (Program)		
Project Number:	N/A	Capitalization Criteria:	Extension
Project Initiator:	Mark Emmanuel	Enterprise Project Driver :	3. Reliability or Life Cycle Replacement
Project Manager:	Mark Emmanuel	Primary BU:	ENGLP – 5B
Project Sponsor(s):	Darren McCrank Director, Ontario Operations	Filing/Regulatory Reference:	General Plant

FUNDING BY YEAR						
	2025	2026	2027	2028	2029	TOTAL
Capital Expenditure ($)	$75,520	$80,000	$87,300	$91,510	$95,700	$430,030
External Contribution ($)						
Net Capital Cost TOTAL	$75,520	$80,000	$87,300	$91,510	$95,700	$430,030
Capital Addition (%)	100%	100%	100%	100%	100%	100%
Operating Expenditure ($)	0	0	0	0	0	0

1. Background and Justification

The Annual Fleet Replacement Program accounts for the replacement of fleet, including light trucks and vans, medium-duty trucks and construction equipment. Existing fleet which have been assessed at economic end-of -life units are to be traded for new fleet units. Repairs and maintenance costs of existing units are expected to remain high with continued operation. New fleet units will have reduced repair and maintenance costs.

The timing for fleet replacement ensures that units are traded before they deteriorate to a degree that represents an operational safety hazard. The vehicles selected for replacement within this USP period represent units required to maintain safe and reliable operation of ENGLP's system.

Condition assessments have been completed on all fleet vehicles to determine need for trade. Condition assessments include factors such as age, mileage, engine hours, type of service (harsh, offroad, paved), reliability history, maintenance cost history, interior/exterior condition (ex: rusting), and other as necessary. Assessments are projected out to the year of replacement or past this USP period. Optimal timing includes spreading out the capital costs over the USP period and also to prolong the life of the vehicle to the furthest extent possible to reduce the rate impact.

2. Alternatives Considered

Repairing and extending the life of individual units was considered as an alternative to trade. This was not deemed as feasible given the condition assessment of the identified vehicles. Extending the life risks driver safety, work practice safety and reliability. While this may reduce capital costs, this would result in high operational expense costs and downtime of the fleet risking the ability to maintain the system and respond to emergencies.

3. Scope of Recommended Option

ENGLP's Aylmer utility currently has a fleet of 9 light-duty trucks and service vans. In addition, the utility also has a mini excavator, a Vermeer plow, a trailered vac unit and a trailer for hauling mobile equipment. The following replacement plan is recommended.

Year	Vehicle Year (Unit #)	Vehicle Type	Trade In	Dollar Amount
2025	2019 (Truck #04)	Chevolet Silverado 1500	Yes	$85,000
2026	2020 (Truck #15)	Chevolet Silverado 1500	Yes	85,000
2027	2022 (Truck #18)	Chevolet Silverado 2500HD	Yes	$90,000
2028	2022 (Truck #17)	Chevolet Silverado 2500HD	Yes	$90,000
2029	2022 (Truck #110)	Jeep Cherokee	Yes	$90,000

4. Cost and Cost Basis

Costs have been estimated based on historical experience, plus inflationary impacts.

5. Timelines and Milestones

The Fleet Replacement program is slated to be completed within the General Plant annual program 2025-2029 budget years. The procurement is completed in advance due to long lead times.

6. Execution Risks

The Aylmer service area is relatively large and the utility relies heavily on its fleet to monitor the natural gas distribution system, make customer service calls and emergency response. Vehicle replacement must be managed appropriately to maintain reliability and productivity, and avoid high maintenance costs (i.e. overall lifecycle costs).

7. Preliminary Execution Strategy

Develop a good request for proposal practice and issue out with plenty of lead time. Once the USP is approved, ENGLP will take this fleet vehicle replacement plan to our vendors to start the process.

Project Name:	**General Plant - IT Hardware and OT Cyber Security Enhancement (Program)**		
Project Number	TBD	**Project/Program**	Project
BU:	ENGLP	**Capitalization Criteria:**	The probable creation or acquisition of a new tangible or intangible item with a useful life greater than one year
Project Initiator:	Gabriela Moise, Senior Manager, IT Planning & Architecture		Select Capitalization Reason
Project Manager:	TBD		Select Capitalization Reason
Project Sponsor:	Reza Khalili, Director Application Services		Select Capitalization Reason
Filing Category:	IT Hardware Life Cycle Replacements and Additions Distribution	**Project Categories**	3. Reliability or Life Cycle Replacement

	2025	2026	2027	2028	2029	TOTAL
Capital Expenditure ($)	$30,000	$30,000	$30,000	$30,000	$30,000	$150,000
External Contribution ($)						
TOTAL	$30,000	$30,000	$30,000	$30,000	$30,000	$150,000
Capital Addition (%)	100%	100%	100%	100%	100%	100%
Operating Expenditure ($)						

1. Background and Justification

1) IT Hardware Replacement

The purpose of this project is to perform lifecycle replacements for the desktop and/or laptop computers, peripherals, tablets, monitors, printers, and smartphones that have reached the end of their useful life. This project scope also includes any purchase of new equipment to support business growth and any replacements of devices.

The following criteria are evaluated when ENGLP is considering the replacement of IT hardware:

- it no longer functions properly or is obsolete

- maintenance or repairs are no longer cost effective
- it is no longer technically supported by the manufacturer or other service providers

ENGLP Infrastructure defines and maintains minimum standards for desktop computers, laptops, printers and smartphones. These standards are used to evaluate equipment that has reached an age where they require replacement.

For obsolete desktop and laptop computers, ENGLP business units will first try to redeploy existing equipment (that meets minimum standards) that has become available due to business process or organizational changes before purchasing new equipment.

For large printers that provide employees with centralized printing, scanning and faxing; the replacement cycle is every 5-years or when the printer's recommended page count has been met (whichever comes first).

Smartphones were previously purchased leveraging the vendor's device purchase plan and device costs were expensed monthly. In mid-2018 however, ENGLP changed its approach to purchasing smartphones. This was driven by the Wireless contract renewal changes to the pay-per-use model, as the previous device payment plan was no longer part of the offering. As a result, business units are now required to purchase smartphones outright and capitalize the costs as part of the BU's IT Hardware project.

ENGLP takes the following steps to minimize the capital expenditures associated with hardware device purchases:

Business units will only replace hardware that does not meet the minimum requirements

All purchases will be made on an ENGLP-wide basis through a common Service Desk supplier so that bulk discounts on hardware can be obtained.

2) OT Cyber Security Enhancement

This project will give us the tools we need to stay ahead of the threats and maintain compliance with the Ontario Cyber Security Framework. This will include things like endpoint protection, OT protocol inspection, firewalls and other tools or assessments to detect and respond to threats. We combined our OT cyber security efforts amongst the Ontario business units to achieve cost savings and operational efficiencies for our combined ratepayers.

2. Alternatives Considered

Alternatives Considered	
Alternate Rational qualitative/quantitative benefits for each and the proposed solution:	Cost / Benefits
Option 1 – Status Quo There are no expected benefits of remaining with IT hardware that is obsolete or beyond its useful lifespan. Potential impacts to business operations include: • No vendor support for dated software and equipment • Reduced operational efficiencies due to aged equipment performance • New staff require IT hardware to perform work tasks	*$0 / benefits*
Option 2 – Perform lifecycle replacements Continue with annual IT hardware lifecycle replacement process following Infrastructure guidelines for out of support / end of life IT hardware. This includes the purchase of new equipment to support business growth.	*$150,000*

For OT cyber security threats evolve too fast to rely on yesterday's protection. There is a strong need to be proactive. No alternate option.

3. Scope of Recommended Option

This project will coordinate the purchase, configuration, and installation of IT Hardware adhering to ENGLP's evergreen schedules and working with our approved Service Desk contractor.

	In Scope	**Out of Scope**
Process	• Purchase and install office workstation computer systems. • Purchase and deploy mobile field laptops. • Purchase and install network and multi-function printers. • Purchase and install monitors. • Purchase mobile phones for the business.	All other processes that do not align with the replacement or addition of IT computer hardware.

	• Manage the IT hardware lifecycle replacements and additions capital hardware budget and assist in the coordination of computer inventories for the business.	
Organization	• 5B – Commercial Services (Aylmer)	All other ENGLP business units.
Location	• Ontario	All other locations.
Data	• Physical inventories: the Asset Management team will ensure full physical inventories will be completed through the validation of the existing inventory list. • Existing business related data that falls within ENGLP's information retention policies.	All other data.
Application	• TELUS Service Request (TSR) system: orders will be processed through the TSR system. • Applications that are legally licensed, fall within ENGLP's software licensing policies, and are required for replacement of computer hardware.	Any other applications.

The scope of the IT Hardware replacements for the BUs are determined from the Infrastructure evergreen inventory estimates provided in March 2023.

Notes:

Desktop, Laptop, Tablet/IPAD, and Printer data from Hardware Evergreen

Cell Phone data from Telecom Team.

The scope for OT Cyber Security enhancement is cyber security tools for ENGLP's OT systems only. General computing and IT systems are not in scope.

4. Cost and Cost Basis

The estimate was achieved by interviewing key Infrastructure resources responsible for the evergreen program and the TELUS contract, the Telecom analyst, and previous project managers.

2025 Project

	Capital	Operating	Total	Comments
Labour: Internal IT	$0	$0	$0	
Labour: Internal BU	$0	$0	$0	
Labour: External	$3,322	$0	$3,322	
Hardware	$21,518	$0	$21,518	
Software	$0	$0	$0	
Miscellaneous	$0	$0	$0	
IDC	$0	$0	$0	
Contingency	$3,413	$0	$3,413	15%
Capital Overhead	$0	$0	$0	
Total Before Inflation	**$28,253**	**$0**	**$28,253**	
Inflation	$1,747	$0	$1,747	
TOTAL	**$30,000**	**$0**	**$30,000**	

2026 Project

	Capital	Operating	Total	Comments
Labour: Internal IT	$0	$0	$0	
Labour: Internal BU	$0	$0	$0	
Labour: External	$3,322	$0	$3,322	
Hardware	$21,518	$0	$21,518	
Software	$0	$0	$0	
Miscellaneous	$0	$0	$0	
IDC	$0	$0	$0	
Contingency	$3,413	$0	$3,413	15%
Capital Overhead	$0	$0	$0	
Total Before Inflation	**$28,253**	**$0**	**$28,253**	
Inflation	$1,747	$0	$1,747	
TOTAL	**$30,000**	**$0**	**$30,000**	

2027 Project

	Capital	Operating	Total	Comments
Labour: Internal IT	$0	$0	$0	
Labour: Internal BU	$0	$0	$0	
Labour: External	$3,322	$0	$3,322	
Hardware	$21,518	$0	$21,518	
Software	$0	$0	$0	

Miscellaneous	$0	$0	$0	
IDC	$0	$0	$0	
Contingency	$3,413	$0	$3,413	15%
Capital Overhead	$0	$0	$0	
Total Before Inflation	**$28,253**	**$0**	**$28,253**	
Inflation	$1,747	$0	$1,747	
TOTAL	**$30,000**	**$0**	**$30,000**	

2028 Project

	Capital	Operating	Total	Comments
Labour: Internal IT	$0	$0	$0	
Labour: Internal BU	$0	$0	$0	
Labour: External	$3,322	$0	$3,322	
Hardware	$21,518	$0	$21,518	
Software	$0	$0	$0	
Miscellaneous	$0	$0	$0	
IDC	$0	$0	$0	
Contingency	$3,413	$0	$3,413	15%
Capital Overhead	$0	$0	$0	
Total Before Inflation	**$28,253**	**$0**	**$28,253**	
Inflation	$1,747	$0	$1,747	
TOTAL	**$30,000**	**$0**	**$30,000**	

2029 Project

	Capital	Operating	Total	Comments
Labour: Internal IT	$0	$0	$0	
Labour: Internal BU	$0	$0	$0	
Labour: External	$3,322	$0	$3,322	
Hardware	$21,518	$0	$21,518	
Software	$0	$0	$0	
Miscellaneous	$0	$0	$0	
IDC	$0	$0	$0	
Contingency	$3,413	$0	$3,413	15%
Capital Overhead	$0	$0	$0	
Total Before Inflation	**$28,253**	**$0**	**$28,253**	
Inflation	$1,747	$0	$1,747	
TOTAL	**$30,000**	**$0**	**$30,000**	

5. Timelines and Milestones

Each of the annual IT Hardware Replacement projects will run for a full calendar year. There is not a specific go-live date for these projects, rather the hardware will be rolled out throughout each project year based on the sponsor approved Project Charter.

6. Execution Risks

Risks for the implementation of the IT Hardware Replacement project are:

1) Financial Risks

- Incorporated 15% contingency
- Inflation applied per rate tables which is consistent with other planned projects
- The Service Desk contract is being renegotiated in 2024. As the new Service Desk Rate was not known at the time of PPR creation, a 10% increase in the Service Desk Rate was used in the development of the PPR

2) Implementation Risks

- The project will be executed following ENGLP's IT project delivery model. It will have a Project Manager and Service Desk resources to execute the evergreen lifecycle replacements. These projects will be governed by a steering committee.
- Hardware availability due to supply chain and other constraints will be managed by allowing for as much lead-time as possible for the acquisition of hardware. If required, IT Purchasing may look into alternate providers

7. Preliminary Execution Strategy

Existing processes and vendor contracts will be used in the execution of these projects.

APPENDICES

A1 – Cloud Risk Profile

#	Cloud Risk	Mark X / Provide Details
1	Related to Cloud? If answer is "Yes", answer questions 2-6.	☐ Yes ☒ No
2	Provide Cloud Data Description	*<Description summary>*

3	Data Risk Classification	☐ Unrestricted ☐ Protected ☐ Confidential ☐ Restricted ☐ Prohibited	
4	Security Controls meet requirements of Data Risk Classification?	☐ Yes ☐ No	Exemption Justification: *<justification summary>*
5	Cloud Vendor Confidence:	☐ Excellent ☐ Good ☐ Poor ☐ Unknown	
6	Internal IT Support Requirements	☐ 24x7 ☐ 8x5 ☐ None	

A2 – NPV

2025

NPV and Payback											
Business Unit Discount Rate:	8.00%										
Year	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Net Present Value Analysis											
One-Time Costs	(0.03)										
Recurring Costs											
Total Costs	(0.03)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Tangible Benefits (Expected Revenue)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NET BENEFIT (Total Cash Flow)	(0.03)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Overall NPV											(0.03)
IRR											<0%
Discount Payback											
Present Value Total Cash Flow	(0.03)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Present Value Cumulative Cash Flow	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)
Discount Payback Year											>10

Tangible Benefits (Expected Revenue)

List any tangible benefits associated with this project

	BU	RC	Activity	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year8	Year 9	Year 10
Benefit Name (e.g., hardware reduction)														
Benefit Name (e.g., license reduction)														
Benefit Name (e.g., hardware reduction)														
Total Tangible Benefits (Expected Revenue)				0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Intangible Benefits

List any intangible benefits associated with this project (e.g., process improvement etc.)

2026

NPV and Payback											
Business Unit Discount Rate:	8.00%										
Year	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Net Present Value Analysis											
One-Time Costs	(0.0041)										
Recurring Costs											
Total Costs	(0.0041)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total Tangible Benefits (Expected Revenue)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NET BENEFIT (Total Cash Flow)	(0.0041)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Overall NPV											(0.004)
IRR											<0%
Discount Payback											
Present Value Total Cash Flow	(0.004)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Present Value Cumulative Cash Flow	(0.004)	(0.004)	(0.004)	(0.004)	(0.004)	(0.004)	(0.004)	(0.004)	(0.004)	(0.004)	(0.004)
Discount Payback Year											>10

Tangible Benefits (Expected Revenue)

List any tangible benefits associated with this project

	BU	RC	Activity	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year8	Year 9	Year 10
Benefit Name (e.g., hardware reduction)														
Benefit Name (e.g., license reduction)														
Benefit Name (e.g., hardware reduction)														
Total Tangible Benefits (Expected Revenue)				0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Intangible Benefits

List any intangible benefits associated with this project (e.g., process improvement etc.)

2027

NPV and Payback											
Business Unit Discount Rate:	8.00%										
Year	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Net Present Value Analysis											
One-Time Costs	(0.06)										
Recurring Costs											
Total Costs	(0.06)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Tangible Benefits (Expected Revenue)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NET BENEFIT (Total Cash Flow)	(0.06)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Overall NPV											(0.06)
IRR											<0%
Discount Payback											
Present Value Total Cash Flow	(0.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Present Value Cumulative Cash Flow	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
Discount Payback Year											>10

Tangible Benefits (Expected Revenue)

List any tangible benefits associated with this project

	BU	RC	Activity	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year8	Year 9	Year 10
Benefit Name (e.g., hardware reduction)														
Benefit Name (e.g., license reduction)														
Benefit Name (e.g., hardware reduction)														
Total Tangible Benefits (Expected Revenue)				0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Intangible Benefits

List any intangible benefits associated with this project (e.g., process improvement etc.)

2028

NPV and Payback											
Business Unit Discount Rate:	8.00%										
Year	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Net Present Value Analysis											
One-Time Costs	(0.02)										
Recurring Costs											
Total Costs	(0.02)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Tangible Benefits (Expected Revenue)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NET BENEFIT (Total Cash Flow)	(0.02)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Overall NPV											(0.02)
IRR											<0%
Discount Payback											
Present Value Total Cash Flow	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Present Value Cumulative Cash Flow	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Discount Payback Year											>10

Tangible Benefits (Expected Revenue)

List any tangible benefits associated with this project

	BU	RC	Activity	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year8	Year 9	Year 10
Benefit Name (e.g., hardware reduction)														
Benefit Name (e.g., license reduction)														
Benefit Name (e.g., hardware reduction)														
Total Tangible Benefits (Expected Revenue)				0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Intangible Benefits

List any intangible benefits associated with this project (e.g., process improvement etc.)

2029

NPV and Payback											
Business Unit Discount Rate:	8.00%										
Year	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Net Present Value Analysis											
One-Time Costs	(0.06)										
Recurring Costs											
Total Costs	(0.06)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Tangible Benefits (Expected Revenue)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NET BENEFIT (Total Cash Flow)	(0.06)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Overall NPV											(0.06)
IRR											<0%
Discount Payback											
Present Value Total Cash Flow	(0.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Present Value Cumulative Cash Flow	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
Discount Payback Year											>10

Tangible Benefits (Expected Revenue)

List any tangible benefits associated with this project

	BU	RC	Activity	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year8	Year 9	Year 10
Benefit Name (e.g., hardware reduction)														
Benefit Name (e.g., license reduction)														
Benefit Name (e.g., hardware reduction)														
Total Tangible Benefits (Expected Revenue)				0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Intangible Benefits

List any intangible benefits associated with this project (e.g., process improvement etc.)

A3 – Priority Matrix

For each year, the priority matrix will be as follows:

Priority Matrix		
Information	Evaluation Details	Sub Score
Duration	<= 12 Months	
Project Category	Sustain/Lifecycle	30
Strategic Alignment	High	15
Regulatory Approval Status	No Regulatory Approval	5
Improve Customer Service	Moderate	10
IT Resource/Complexity Risk	Low	10
Financial Impact - Payback Yea	> 10 Year	0
Financial Impact - IRR	<0%	0
Total Score (Max 100)		70

Project Name:	ENGLP Aylmer - General Plant Mobile Apps (Program)		
Project Number	TBD	Project/Program	Project
BU:	5B Aylmer	Capitalization Criteria:	The probable creation or acquisition of a new tangible or intangible item with a useful life greater than one year
Project Initiator:	TBD		Select Capitalization Reason
Project Manager:	TBD		Select Capitalization Reason
Project Sponsor:	Darren McCrank		Select Capitalization Reason
Filing Category:		Project Categories	3. Reliability or Life Cycle Replacement

FUNDING BY YEAR						
	2025	2026	2027	2028	2029	TOTAL
Capital Expenditure ($)	$20,000	$20,000	$20,000	$20,000	$20,000	$100,000
External Contribution ($)						
TOTAL	$20,000	$20,000	$20,000	$20,000	$20,000	$100,000
Capital Addition (%)	100%	100%	100%	100%	100%	%100
Operating Expenditure ($)						

1. Background and Justification

While desktop computers have altered the way business is conducted in an office environment; extending office applications to the field staff have historically been challenging as complex enterprise applications do not easily mesh with the working environment and skillsets of field staff.

With the emergence of mobile app technology there has been a general trend for all industries to leverage the simplicity and mobility of mobile apps concepts to extend the benefits of existing enterprise office applications to the field.

Specific mobile app use cases for ENGLP will be determined closer to project chartering. The use cases inventory for all BUs is managed by the Mobile Applications Steering Committee and has BU representation to ensure needs are prioritized and championed.

This yearly bucket project is to ensure ENGLP can leverage this platform by adopting apps to support field work and eliminate longstanding paper processes with simple to use tools and to provide data and reporting that is readily available for use.

2. Alternatives Considered

Alternatives Considered	
Alternate Rational qualitative/quantitative benefits for each and the proposed solution:	Cost / Benefits
Yearly Mobile Apps project (recommended) The benefits of leveraging mobile application technologies include: • Improve the user experience based on feedback gathered from users. • Provide field employees with mobile application technologies to improve work efficiency and customer services. • Implement necessary mobile applications and changes based on the business requirements and needs.	*$100,000 / benefits*
Status Quo The disadvantages of not expanding the use of mobile application technology will continue include: • Existing processes that utilize paper to track critical information will continue. • Reconciliation of paper-based information with corporate systems will continue. • Field workers will not have easy access to corporate data required to perform their work. • Monitoring and compliance workflows will continue to be less efficient than would be possible with mobile apps. As a result, this alternative is not recommended.	*X $ / benefits*

3. Scope of Recommended Option

The detailed scope per year is determined based on a prioritization framework and approved by a Steering Committee.

In 2025-2029, the Mobile Application projects will:

- Identify the project needs and detail the business requirements through the Mobile Apps Steering Committee

- Work closely with the field staff to develop a mobile application to address identified business needs and requirements.
- Roll out the mobile application to the appropriate teams

4. Cost and Cost Basis

The detailed breakdown cost of the budgeted amount for Mobile Apps for the respectively years throughout 2025-2029.

2025	Capital	Operating	Total	Comments
Labour: Internal IT	$10,000	$0	$10,000	
Labour: Internal BU	$0	$0	$0	
Labour: External	$5,000	$0	$5,000	
Hardware	$0	$0	$0	
Software	$0	$0	$0	
Miscellaneous	$0	$0	$0	
IDC	$0	$0	$0	
Contingency	$3,000	$0	$3,000	20%
Capital Overhead	$0	$0	$0	
Total Before Inflation	$18,000	$0	$18,000	
Inflation	$2,000	$0	$2,000	
TOTAL	$20,000	$0	$20,000	

2026	Capital	Operating	Total	Comments
Labour: Internal IT	$10,000	$0	$10,000	
Labour: Internal BU	$0	$0	$0	
Labour: External	$5,000	$0	$5,000	
Hardware	$0	$0	$0	
Software	$0	$0	$0	
Miscellaneous	$0	$0	$0	
IDC	$0	$0	$0	
Contingency	$3,000	$0	$3,000	20%
Capital Overhead	$0	$0	$0	
Total Before Inflation	$18,000	$0	$18,000	
Inflation	$2,000	$0	$2,000	
TOTAL	$20,000	$0	$20,000	

2027	Capital	Operating	Total	Comments
Labour: Internal IT	$10,000	$0	$10,000	
Labour: Internal BU	$0	$0	$0	
Labour: External	$5,000	$0	$5,000	

Hardware	$0	$0	$0	
Software	$0	$0	$0	
Miscellaneous	$0	$0	$0	
IDC	$0	$0	$0	
Contingency	$3,000	$0	$3,000	20%
Capital Overhead	$0	$0	$0	
Total Before Inflation	$18,000	$0	$18,000	
Inflation	$2,000	$0	$2,000	
TOTAL	$20,000	$0	$20,000	

2028	Capital	Operating	Total	Comments
Labour: Internal IT	$10,000	$0	$10,000	
Labour: Internal BU	$0	$0	$0	
Labour: External	$5,000	$0	$5,000	
Hardware	$0	$0	$0	
Software	$0	$0	$0	
Miscellaneous	$0	$0	$0	
IDC	$0	$0	$0	
Contingency	$3,000	$0	$3,000	20%
Capital Overhead	$0	$0	$0	
Total Before Inflation	$18,000	$0	$18,000	
Inflation	$2,000	$0	$2,000	
TOTAL	$20,000	$0	$20,000	

2029	Capital	Operating	Total	Comments
Labour: Internal IT	$10,000	$0	$10,000	
Labour: Internal BU	$0	$0	$0	
Labour: External	$5,000	$0	$5,000	
Hardware	$0	$0	$0	
Software	$0	$0	$0	
Miscellaneous	$0	$0	$0	
IDC	$0	$0	$0	
Contingency	$3,000	$0	$3,000	20%
Capital Overhead	$0	$0	$0	
Total Before Inflation	$18,000	$0	$18,000	
Inflation	$2,000	$0	$2,000	
TOTAL	$20,000	$0	$20,000	

5. Timelines and Milestones

The project will begin in January and complete by December, exact timelines will be determined in the project plan per year.

No high-level milestones can be identified at this time.

6. Execution Risks

Risks for the implementation of the Mobile Applications projects are:

1) Financial Risks
- Incorporated 20% contingency

2) Implementation Risks
- The project will be executed following ENGLP's IT project delivery model. It will have a project manager, business analysts and testers (where required), and be governed by a steering committee.

7. Preliminary Execution Strategy

This project will be using an Agile software development methodology, which allows ENGLP to quickly respond to emerging business needs, and the project will be executed using existing technologies, contracts and processes. This is a year over year project, so the approach remains the same. The Mobile Apps Steering Committee will review and approve specific requirements / use case scope prior to work commencing

APPENDICES

A1 – Cloud Risk Profile

#	Cloud Risk	Mark X / Provide Details	
1	Related to Cloud? If answer is "Yes", answer questions 2-6.	No	
2	Provide Cloud Data Description	*<Description summary>*	
3	Data Risk Classification	Choose an item.	
4	Security Controls meet requirements of Data Risk Classification?	Choose an item.	Exemption Justification: *<justification summary>*

5	Cloud Vendor Confidence:	Choose an item.	
6	Internal IT Support Requirements	Choose an item.	

A2 – NPV

NPV and Payback											
Business Unit Discount Rate:	8.00%										
IT Project Target Rate of Return:	25%										
Year	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2033
Year #	0	1	2	3	4	5	6	7	8	9	10
Net Present Value Analysis											
One-Time Costs	-$0.03	$ (0.03)	$ (0.03)	$ (0.03)	$ (0.03)						
Recurring Costs	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
Total Costs	$ (0.03)	$ (0.03)	$ (0.03)	$ (0.03)	$ (0.03)	$ -	$ -	$ -	$ -	$ -	$ -
Total Tangible Benefits (Expected Revenue)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NET BENEFIT (Total Cash Flow)	$ (0.03)	$ (0.03)	$ (0.03)	$ (0.03)	$ (0.03)	$ -	$ -	$ -	$ -	$ -	$ -
Overall NPV											$ (0.13)
IRR											<0%
Payback											
Cumulative Cash Flow	$ (0.03)	$ (0.06)	$ (0.09)	$ (0.12)	$ (0.15)	$ (0.15)	$ (0.15)	$ (0.15)	$ (0.15)	$ (0.15)	$ (0.15)
Payback Year Fraction	-	-	-	-	-	-	-	-	-	-	-
Payback Year											>10
Discount Payback											
Present Value Total Cash Flow	$ (0.03)	$ (0.03)	$ (0.03)	$ (0.02)	$ (0.02)	$ -	$ -	$ -	$ -	$ -	$ -
Present Value Cumulative Cash Flow	$ (0.03)	$ (0.06)	$ (0.08)	$ (0.11)	$ (0.13)	$ (0.13)	$ (0.13)	$ (0.13)	$ (0.13)	$ (0.13)	$ (0.13)
Present Value Payback Year Fraction	-	-	-	-	-	-	-	-	-	-	-
Discount Payback Year											>10

Tangible Benefits (Expected Revenue)

List any tangile benefits associated with this project

	BU	RC	Activity	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year8	Year 9	Year 10
Benefit Name (e.g., staff reduction)														
Benefit Name (e.g., license reduction)														
Benefit Name (e.g., hardware reduction)														
Benefit Name, (e.g., process improvement cost savings)														
Total Tangible Benefits (Expected Revenue)				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

A3 – Priority Matrix

Instructions (fill in light blue cells)
1) Fill in the table below and use the "Priority Matrix List Details" as reference

Priority Matrix		
Information	Evaluation Details	Sub Score
Duration	>= 12 Months	
Project Category	Innovate	5
Strategic Alignment	Moderate	10
Regulatory Approval Status	No Regulatory Approval	5
Improve Customer Service	Moderate	10
IT Resource/Complexity Risk	Low	10
Financial Impact - Payback Year	> 10 Year	0
Financial Impact - IRR	<0%	0
Total Score (Max 100)		**40**

Project Name:	ENGLP Aylmer General Plant Small Tools and Equipment (Program)		
Project Number:	N/A	Capitalization Criteria:	Creation/Acquisition
Project Initiator:	Mark Emmanuel	Enterprise Project Driver :	3. Reliability or Life Cycle Replacement
Project Manager:	Mark Emmanuel	Primary BU:	ENGLP – 5B
Project Sponsor(s):	Darren McCrank Director, Ontario Operations	Filing/Regulatory Reference:	General Plant

FUNDING BY YEAR						
	2025	2026	2027	2028	2029	TOTAL
Capital Expenditure ($)	$23,030	$22,000	$22,300	$22,510	$22,700	$112,540
External Contribution ($)						
Net Capital Cost TOTAL	$23,030	$22,000	$22,300	$22,510	$22,700	$112,540
Capital Addition (%)	100%	100%	100%	100%	100%	100%
Operating Expenditure ($)	0	0	0	0	0	0

1. Background and Justification

The Small Tools and Work Equipment program accounts for the purchase and replacement of small tools and equipment, as required, including pipe fusion and pinch off tools, pipeline locate equipment, and gas monitors. The program will accommodate the purchase of low cost, small tools and equipment meeting capitalization criteria.

These expenditures are typically high-priority, unforeseen items that are required due to failure. Due to the relatively low cost of the individual items, it would be inefficient to budget, approve and track the purchases as separate individual projects.

2. Alternatives Considered

This program accounts for the purchase and replacement of small tools and equipment, typically high-priority, unforeseen items that are required due to failure. Due to the relatively low cost of the individual items, it would be inefficient to budget, approve and track the purchases as separate individual projects and thus the opportunity to capitalize these investments would likely be missed.

3. Scope of Recommended Option

This program accounts for the purchase and replacement of small tools and equipment, as required, including pipe fusion and pinch off tools, pipeline locate equipment, and gas monitors. The program will accommodate the purchase of low cost, small tools and equipment meeting capitalization criteria.

Individual requests for purchases under the program will be approved by the Program Manager as needed. Details of the purchases will be tracked by the Program Manager to facilitate the project close-out process and capitalization. The Program Manager will be accountable for ensuring purchases meet capitalization criteria.

As a rule, individual items purchased under the program will be greater than $2000 in value. Although the threshold for capitalization used elsewhere within ENGLP is generally $5000, through discussions with Finance, $2000 was deemed to be reasonably material in the case of the Aylmer utility.

4. Cost and Cost Basis

Costs have been estimated based on historical experience, plus inflationary impacts.

5. Timelines and Milestones

The Small Tools and Work Equipment program is an annual program slated to be completed within the General Plant annual program 2025-2029 budget years. Click or tap here to enter text.

6. Execution Risks

These expenditures are typically high-priority, unforeseen items that are required due to failure. Due to the relatively low cost of the individual items, it would be inefficient to budget, approve and track the purchases as separate individual projects.

Project Name:	**ENGLP Aylmer - General Plant Building Refurbishments (Project)**		
Project Number:	N/A	**Capitalization Criteria:**	Improvement
Project Initiator:	Mark Emmanuel	**Enterprise Project Driver :**	3. Reliability or Life Cycle Replacement
Project Manager:	Mark Emmanuel	**Primary BU:**	ENGLP – 5B
Project Sponsor(s):	Darren McCrank Director, Ontario Operations	**Filing/Regulatory Reference:**	General Plant

FUNDING BY YEAR						
	2025	**2026**	**2027**	**2028**	**2029**	**TOTAL**
Capital Expenditure ($)	**$123,530**					**$123,530**
External Contribution ($)						
Net Capital Cost TOTAL						
Capital Addition (%)	**100%**					**100%**
Operating Expenditure ($)	**0**	**0**	**0**	**0**	**0**	**0**

1. Background and Justification

ENGLP intends to include a new storage building (1,500 Sq. ft) in its Aylmer distribution office. The new building is intended to provide storage space for PE pipe, 6” Steel pipe and other equipment as necessary. The dimensions of the building will be 50 feet long X 30 feet wide 14 feet high; One man door; Two roll up doors one on each end; Sheet metal building sides and Recycled asphalt for floor.

The project capital spend of $123,530 is planned for 2025 and intended to be started and completed in a single year and assets put in service by December 31 of that year.

2. Alternatives Considered

N/A

3. Scope of Recommended Option

N/A

4. Cost and Cost Basis

Costs have been estimated based on quote received from CDN Buildings.

Base Building Price :	**$ 42,323.86**
Additional Optional Items	
Installation of Concrete foundation piers 18" dia x 48" deep.	$ 5,887.38
Installation of building as per items listed above.	$ 30,701.73
4" - R13 Insulation blanket with WMP-50 liner Package	$ 11,225.82
29ga Interior wall sheeting	not included
1 - 36"w x 80"h Agri No Rot Composite Man door (white)	$ 1,395.00
2 – 12'w x 12'h G-5000 Insulated O.H. Door with chain fall opener	$ 12,275.43
2 - Runs of eavestrough x 50' long w/down pipes @ approximately, every 30'.	$ 1,190.00
4" - Gravel Base for floor preparation (*** See Note)	$ 3,991.60
5" Thick Concrete Floor (32mpa) with mesh and saw cuts.	$ 10,921.47
TOTAL PRICE: :	**$ 119,912.28**
	plus HST

Included Items:

- 2020 OBC Engineered drawings supplied by "CDN Buildings".
- All material FOB: Address listed on this proposal.

Excluded Items:

- ***Additional fees for building permits, variances, township or CA.***
- ***Site Drainage, Electrical, Heating and plumbing.***

5. Timelines and Milestones

The project capital spend of $123,530 is planned for 2025 and intended to be started and completed in a single year and assets put in service by December 31 of that year.

6. Execution Risks

N/A

7. Preliminary Execution Strategy

N/A

Appendices

Appendix 1 – ENGLP Asset Management Plan (2025-2029)

ENGLP Natural Gas Limited Partnership (Aylmer)

2025 – 2029 Asset Management Plan

Table of Contents

1.0 Executive Summary

ENGLP distributes natural gas in Southern Ontario to approximately ten thousand customers in the Town of Aylmer and the surrounding region. The gas demands in the system are primarily for residential heating, commercial and industrial customers as well as seasonal agricultural customers such as grain drying. ENGLP's distribution assets are classified between four classes: Pipe, Fittings, Measurement & Regulation Equipment, and Valves. Further, there are assets that support the business operations and include Fleet and Equipment, Real Estate Workplace Services and Technology and Information Services.

ENGLP recognizes that asset management is critical to achieving its business objectives and moving toward its vision of being a premier essential services company, trusted by our customers and valued by our shareholder. ENGLP is committed to the effective stewardship of its assets through policy and principles and is committed to applying asset management practices to effectively manage the life cycle of its assets. The Asset Management Program is a component of the Integrity Management Program and ENGLP continues to evolve this program based upon industry best practices and incident learnings.

ENGLP is committed to developing maintenance, operation, and reliability strategies as well as capital programs consistent with its Asset plan guiding principles. The Asset Plan establishes the requirements and estimates the related capital expenditures to support four primary kinds of asset-related investments - Customer Growth, System Reinforcements, System Integrity & Reliability including work on the dedicated 6 inch steel line serving the Integrated Grain Processors Co-op customer ("IGPC").

2.0 ENGLP System Description

ENGLP currently operates two natural gas distribution systems; one in Aylmer, Ontario and another in the region of Southern Bruce, Ontario. The Aylmer natural gas distribution system serves customers in the Town of Aylmer and surrounding region including the towns of Brownsville, Straffordville, Vienna, Copenhagen, Port Burwell, Port Bruce, Springfield, and Belmont.

ENGLP distributes natural gas in Southern Ontario to approximately ten thousand customers in the Town of Aylmer and the surrounding region. The service territory extends south from Highway 401 to the shores of Lake Erie. In addition to the Town of Aylmer, the Aylmer System also serves the municipalities of Thames Centre and Central Elgin, the townships of Bayham, Malahide and South West Oxford. The gas demands in the system are primarily for residential heating, commercial and industrial customers as well as seasonal agricultural customers such as grain drying.

The distribution system was first established in the 1970's and has expanded steadily since then. ENGLP owns and operates the system which consists of approximately 920 kilometers of distribution mains (which includes a 6 inch high pressure steel line) fed by seven Enbridge (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 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.

Below is the ENGLP distribution system map which includes pipe diameters and station locations as well as map of ENGLP service area:

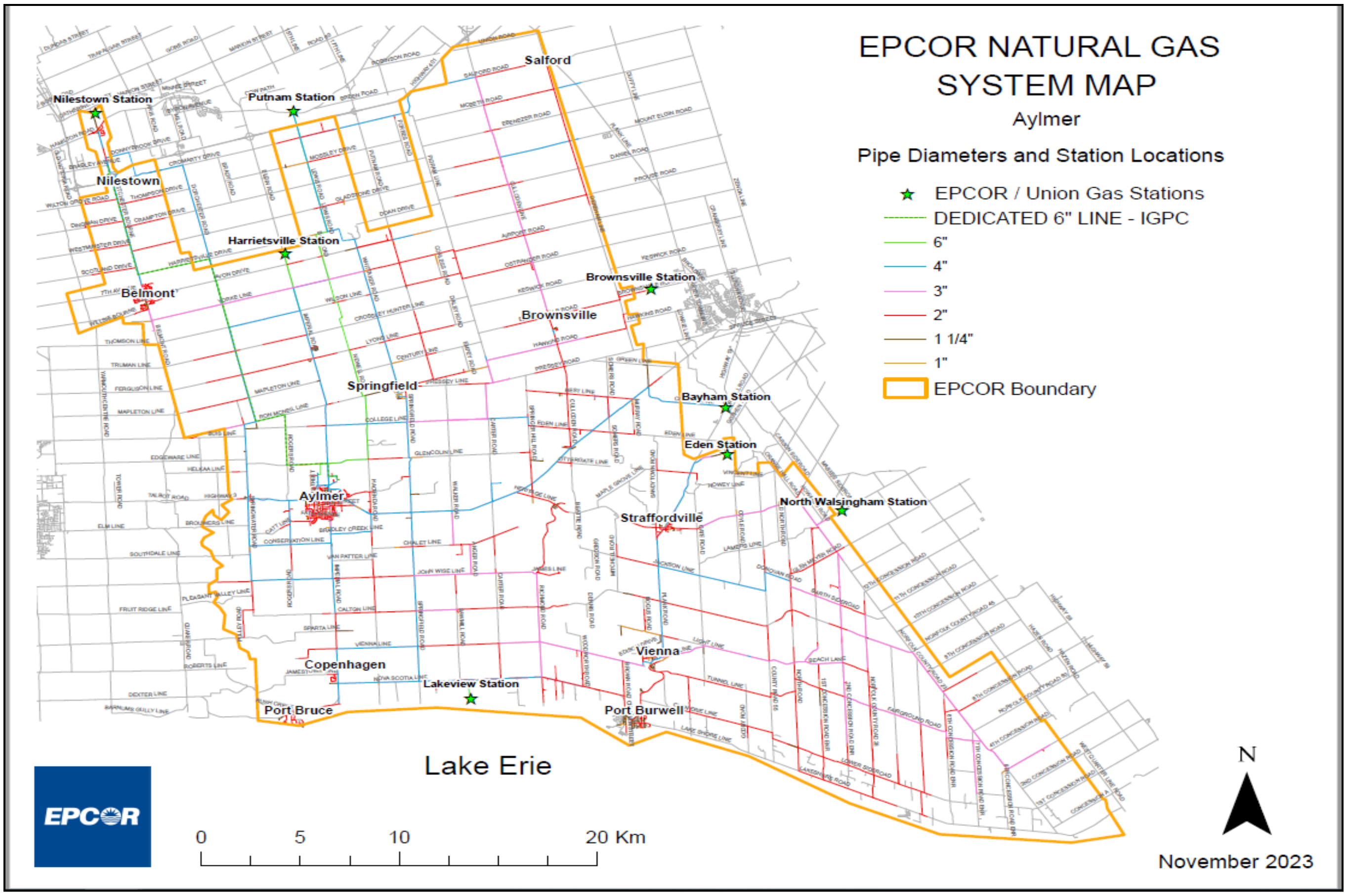


Figure I – ENGLP Distribution System Map

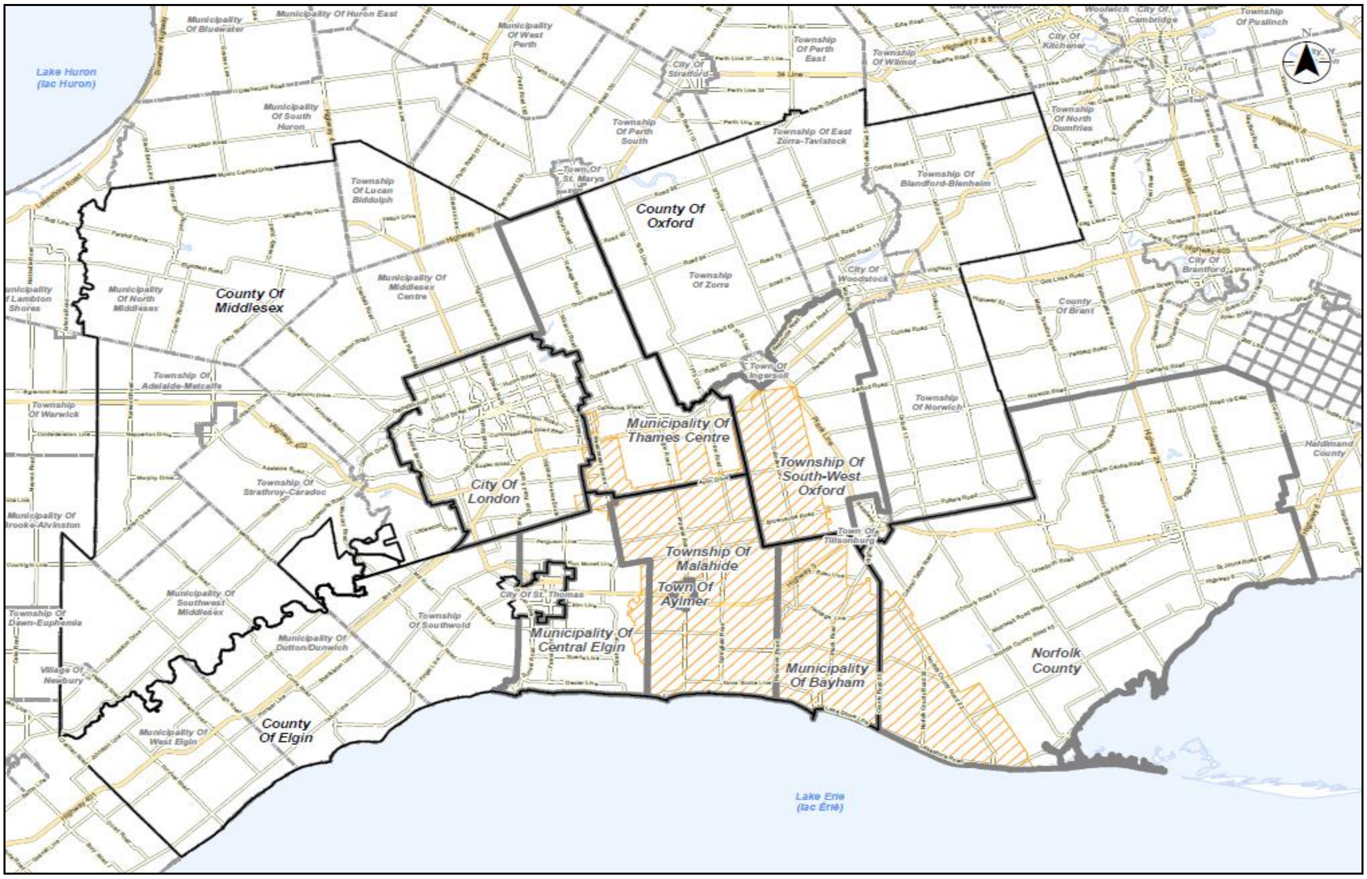


Figure II – ENGLP Service Area

3.0 ENGLP Asset Management Policy and Principles

ENGLP is committed to the effective stewardship of its assets through policy and principles and is committed to applying asset management practices to effectively manage the life cycle of its assets. The Asset Management Program is a component of the Integrity Management Program and provides a systematic approach to managing safety and reliability in the operating unit.

ENGLP recognizes that asset management is critical to achieving its business objectives and moving toward its vision of being a premier essential services company, trusted by our customers and valued by our shareholder. The main asset management goals include public safety, compliance, and value to stakeholders. ENGLP is committed to managing assets in an optimal, sustainable, efficient, safe and environmentally responsible manner, meeting all applicable laws, regulations, standards and codes.

The utility will achieve this by focusing and continually improving upon the following principles:

i. Considering the entire lifecycle of the asset, seeking to minimize the total cost of acquiring, constructing, operating, maintaining, and disposing of assets while recovering that cost and earning a return on our investment.

ii. Assessing and managing risks in accordance with ENGLP's risk management framework to minimize the adverse impacts to public and worker safety, environment, regulatory compliance, reputation, and finances.

iii. Developing maintenance, operation, and reliability strategies as well as capital programs to ensure safe and reliable delivery of natural gas to our ratepayers.

iv. Developing and continuously improving upon a framework to ensure that asset management within ENGLP is integrated, sustainable, systematic, measured, and assessed.

v. Making asset management decisions based on complete, timely, and accurate asset data, using a holistic evaluation of alternatives that balance asset lifecycle cost, risk, and benefit while maintaining customer satisfaction.

vi. Building and maintaining asset management capabilities through the development and retention of the right mix of talented, competent, and motivated team members.

vii. Identifying and engaging public, industry, and government stakeholders in the management of our assets.

4.0 ENGLP Overview of Assets

This section provides an overview of how ENGLP classifies distribution assets, provides an inventory count and age related profiles for some of the asset types. The information provided helps provide context to determine System Integrity and Reliability requirements as well as strategies and plans to address.

ENGLP's distribution assets are classified between four classes: Pipe, Fittings, Measurement & Regulation Equipment, and Valves. Within each class, a hierarchy of assets and sub-types has been determined. This categorization can be found below within Figure III.

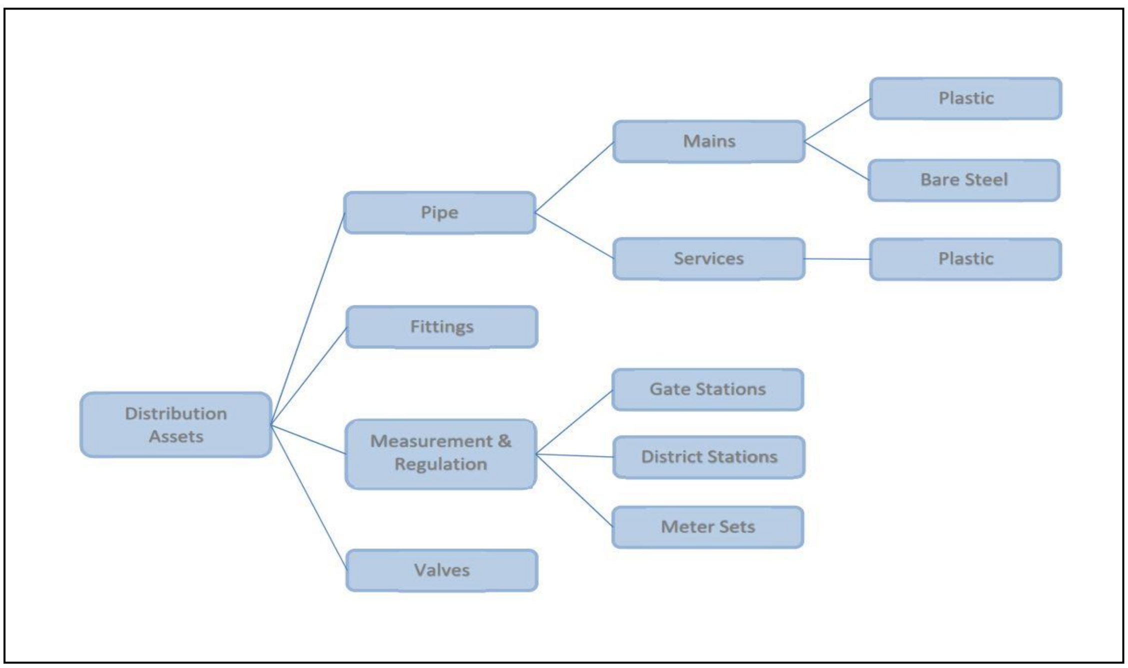


Figure III – ENGLP Distribution Asset Classes

Based on the distribution asset classes above, Table 1 below provides a summary of the managed assets within the current distribution system.

Table 1– ENGLP Inventory of Assets

	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”
District Stations	District Stations	14	
Main Line Valves	Main Line Valves	225	
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	

*Some legacy information may be missing due to collection of specific types of data not part of the records collection standard at the time of installation.

4.1 Understanding Asset Classes by Age, Years in Service and Condition

ENGLP has assets varying in age back until the early 1970’s. It is important to understand factors such as date of installation for certain asset types because materials degrade and as a result asset performance and possible malfunction of the given asset can take place. The access and understanding of this information will help inform the need, scope, and timing of replacement programs.

The age distribution and years of installation for asset classes of distribution mains, distribution services, meters and stations are discussed. This information is based on the current available asset records.

4.1.1 Distribution Mains

The ENGLP distribution network consists of over 900km of distribution main pipeline. The length is split down between the install year, material type, and nominal diameter of each asset and depicted in Figure IV below.

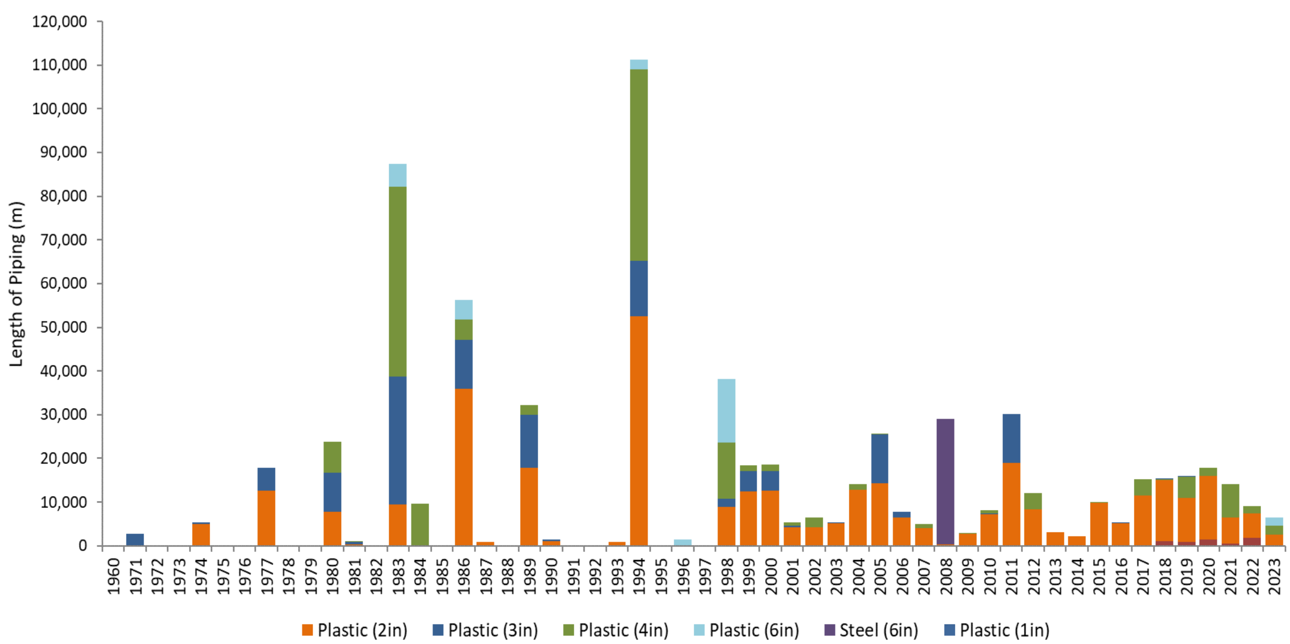


Figure IV – ENGLP Distribution Mains Installed per Year by Material

Understanding age distribution mains is a valuable tool when making decisions for possible system reinforcements or replacements. In the below map, the decade of installation is used to display rural areas with oldest distribution mains compared to recent installations. This data was originally recorded only through paper documents and has since been recorded using GIS. The rural mains are the first to be digitized and illustrated in the map and table below.

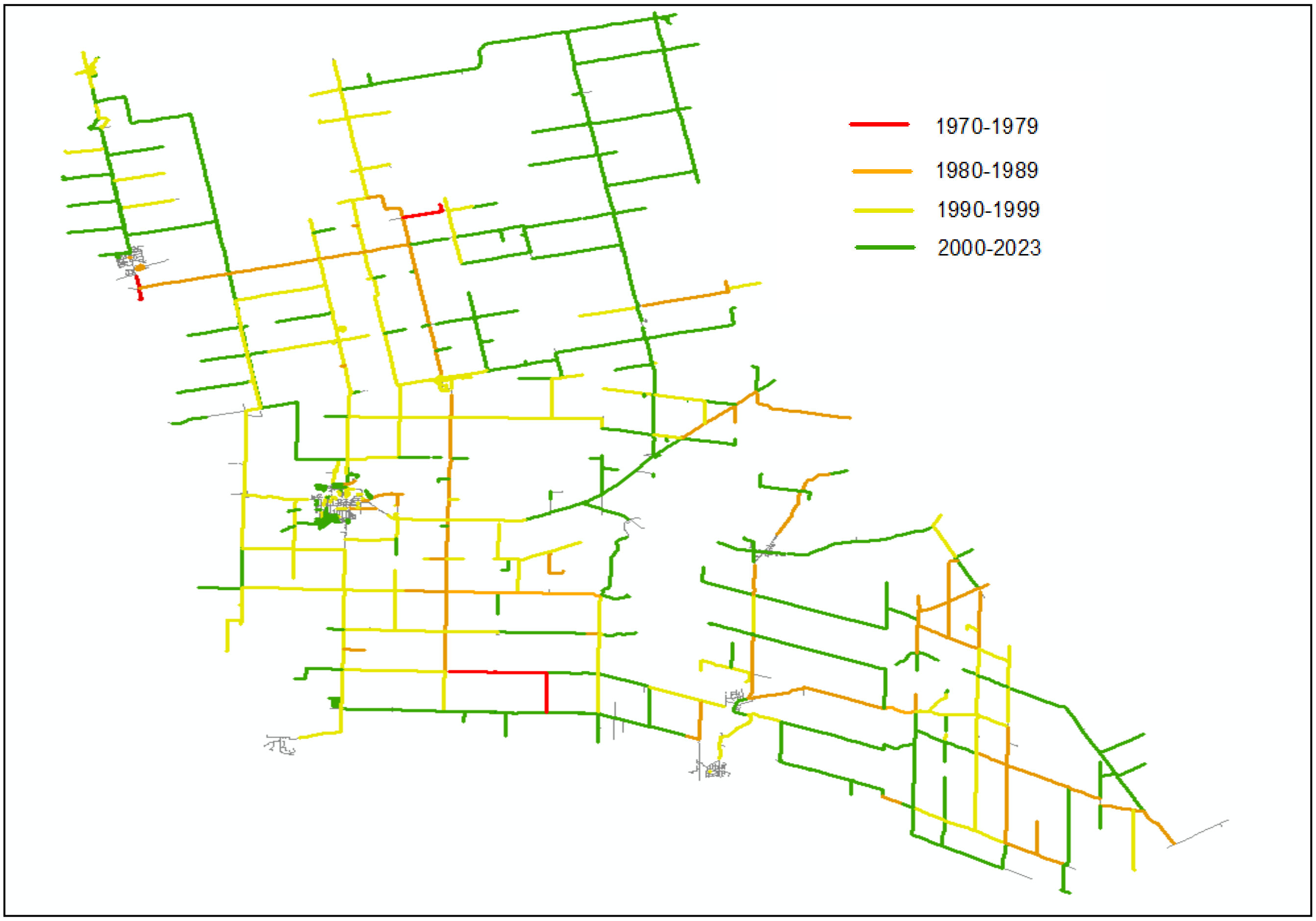


Figure V – ENGLP – Active Distribution Mains by Year of Installation

Table 2 – Rural pipe broken down by Year/Decade of Installation

Decade	Km of Pipe
1970-1979	11
1980-1989	124
1990-1999	240
2000-2009	162
2010-2019	172
2020+	50

4.1.2 Distribution Services

There are approximately 350kms of active services installed in the ENGLP distribution area. Similar to the distribution mains, they are broken down into different categories based upon their material type, nominal diameter, and year of installation.

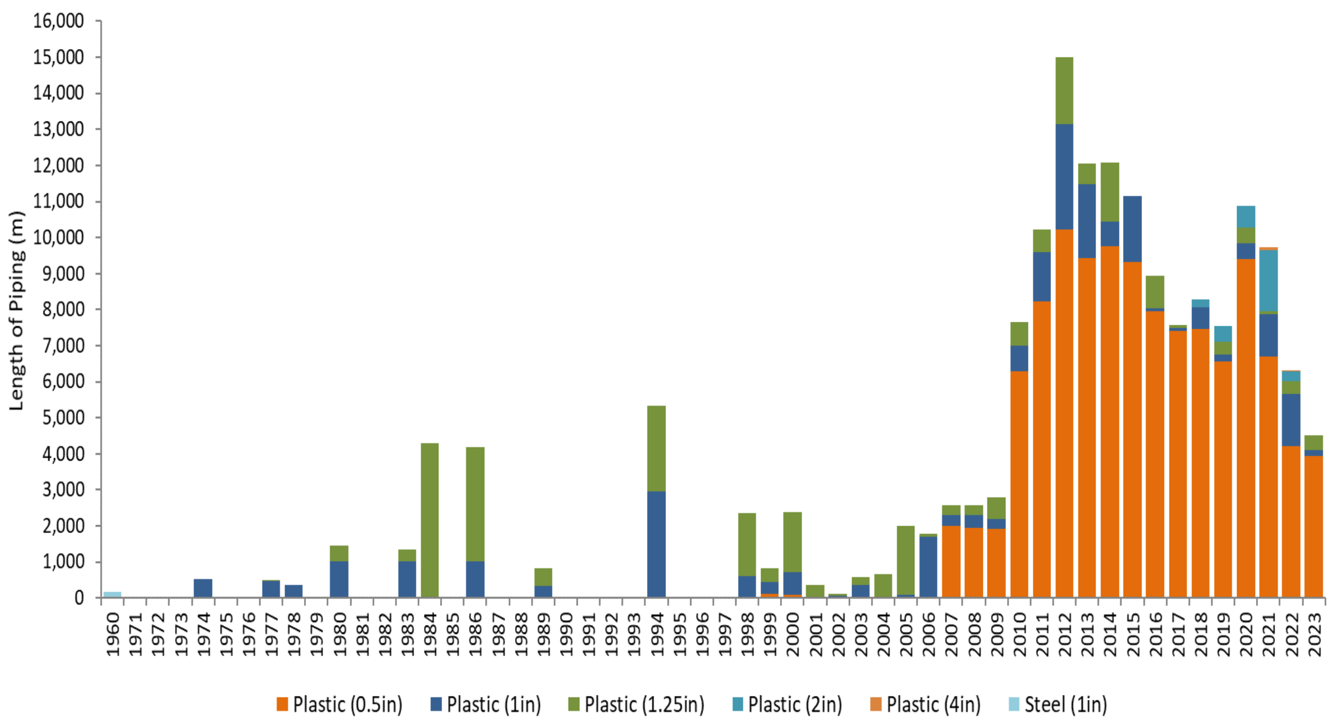


Figure VI – ENGLP Active Services Installed per Year by Material

4.1.3 Meters

The below figure represents meters purchased by year broken down into the different sizes.

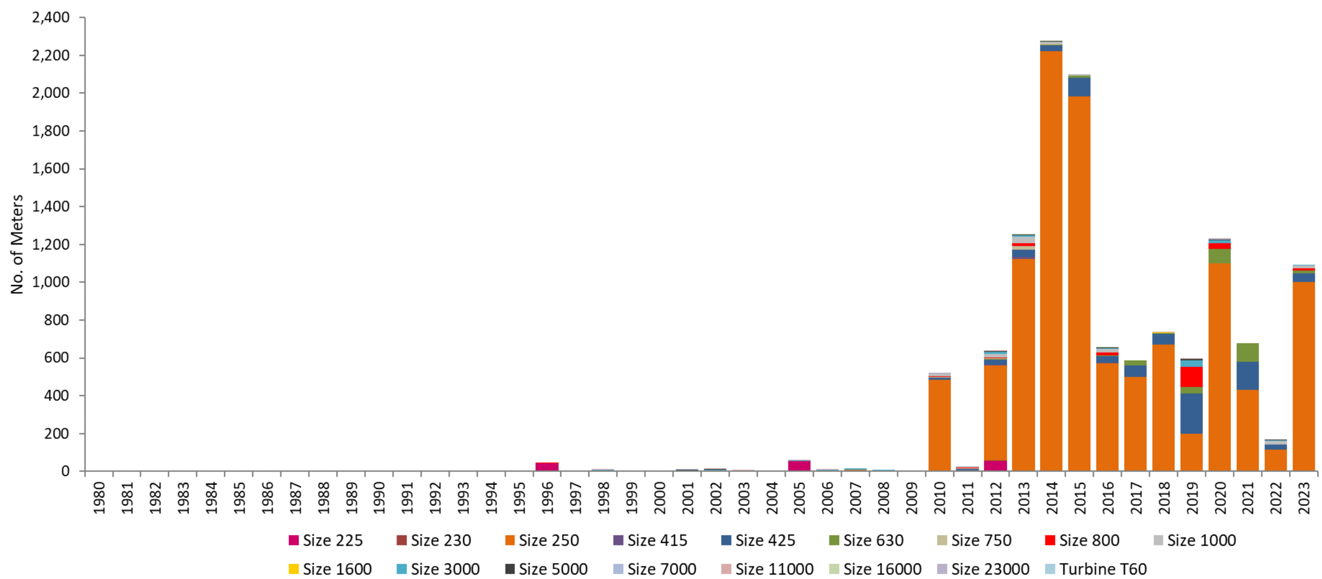


Figure VII – ENGLP Active Meters by Year of Purchase

4.1.4 Stations

Throughout the ENGLP service area, there are currently 8 district stations and 12 sales stations. Although there are many moving parts and different components to these stations, the year of installation represents the entirety of the station and year of service for individual parts is recorded elsewhere.

Capital expenditures for pressure regulating stations is based on the type of work that is being done. Capacity related projects involve the reconstruction of all, or part, of a regulating station. Age and obsolescence drive the need to undertake projects to upgrade the gas preheat systems at district stations. Additionally, odorant system upgrades are driven by capacity, safety, and age and obsolescence.

District stations have been indicated with an asterisk * below.

Table 3 – ENGLP Active District and Sales Stations by Year of Installation

Station	Year
Putnam*	1984
Beech St	1984
Eden*	1989
Harrietsville*	1994
Brown Side Rd	1994
Teal Hill	1994
Bradley Creek	1996
Rogers Rd	1996
Elm St	1997
Delmer*	2003
Nilestown*	2005
North Belmont	2005
Nilestown	2005
Bayham*	2013
Dorchester	2016
North Walsingham*	2016
Hacienda	2018
South Brownsville	2018
Lakeview*	2019
South Belmont	2023
North Brownsville	Unknown
Port Bruce	Unknown

5.0 Risk Management

Operational hazard and risk identification occurs throughout the asset life cycle. ENGLP identifies and evaluates all potential risks to its pipeline distribution systems on a regular basis. Potential threats that must be considered include, but are not limited to, the following categories:

i. Time Dependent Threats – External Corrosion, Internal Corrosion, Stress Corrosion Cracking;
ii. Stable Threats
   a. Manufacturing Related – Defective Pipe Seam, Defective Pipe
   b. Welding/Fabrication Related – External Metal Loss, Defective Pipe Girth Weld and Fabrication Weld, Wrinkle, Dent

   c. Equipment – Gasket/O-Ring Failure, Control/Relief Malfunction, Seal/Pump Packing Failure

iii. Time Independent Threats
   a. Third Party – Damage due to Line Strikes, Previously Damaged Pipe, Vandalism
   b. Incorrect Operational Procedures
   c. Weather Damage – Cold Weather, Lightning, Heavy Rains, Earth Movements

iv. Human Error – Operational or maintenance mishaps, Design mistakes

5.1 Risk Analysis Approach and Selection

The first step in evaluating the potential threats for a pipeline system or segment is to define and gather the necessary data and information that characterize the segments and the potential threats to that segment. For the baseline threat identification and risk analysis, ENGLP has chosen pipeline attributes based upon available, verifiable information, or information that could be attained in a timely manner. The location-specific threats to pipeline integrity are identified, and the public, environmental, and operational consequences of an incident are analyzed. After the initial risk analysis and threat identification is made, updates will be made on a continual basis as new and more current data is made available. Every three (3) years, ENGLP will conduct a review and evaluation of the data needs, data sources, and data quality and consistency. However, changes are also made within the Risk Registry at the time that new risks are identified, or lessons learned.

ENGLP will integrate and update gathered data into geospatial software and the IMP records database. Listed below are examples of attribute data typically gathered as defined in ASME B31.8S, Section 4, and ASME B31.8S, Appendix A.

- External Corrosion Threat Data
- Internal Corrosion Threat Data
- Stress Corrosion Cracking Threat Data
- Manufacturing Threat Data
- Construction Threat Data
- Equipment Threat Data

- Third Party Damage/Utility Strikes Data
- Incorrect Operations Threat Data
- Weather and Outside Force Threat Data

5.2 Risk Analysis Evaluation

ENGLP will conduct a risk assessment that follows CSA Z-662-19 Annex B, and consider the identified threats for each covered segment. ENGLP will use the risk assessment to prioritize the covered segments for the baseline and continual reassessments to determine what additional preventive measures are needed for the covered segments.

ENGLP defines significant risks as those risks, which have the potential to have a significant consequence defined below. These risks are defined also according to the ENGLP Enterprise Risk Matrix which result in an IV-High or III-Medium High risk.

A significant consequence is the result of an incident that harms people or the environment and includes but is not limited to:

- A serious injury or fatality
- An unintended or uncontrolled release of gas > 30,000 m3 (calculated at standard temperature and pressure)
- A significant adverse effect on the environment
- A rupture of the pipeline causing instantaneous release that immediately affects the operation of the pipeline segment, such that the pressure of the segment cannot be maintained
- A toxic plume caused by a band of service fluid or other contaminant (e.g., hydrogen sulfide or smoke) resulting from an incident that causes people, including employees, to take protective measures (e.g., muster, shelter-in-place or evacuation).

Where a significant residual risk is identified, the following response shall be required:

- the undertaking of a more refined level of risk analysis in an effort to reduce the uncertainty or errors that might have led to an overestimate of the risk level; or
- a consideration of options (see CSA Z662-19 Clause N.1.9.6) that might be available to reduce the estimated risk level.

5.2.1 Data Gathering

ENGLP operations personnel continuously gather pipeline data for the ENGLP System as part of regular patrols and other operations activities. The data gathered include annual pipeline leak surveys, continuous monitoring of system pressure, temperature and flowrate data, annual maintenance survey of exposed facilities such as meter and pressure regulator stations, and regular functionality verification of cathodic protection systems.

In addition to the regular operations monitoring, ENGLP also ensures In-line inspection and Cathodic protection surveys are conducted by third party specialized firms, within critical steel sections of its pipeline delivery system.

5.2.2 Data Review and Analysis

Every 3 years, ENGLP will perform a review of data compiled from field activities, maintenance and repair activities, and other operations activities to ensure completeness and accuracy of the data. Described below is an outline for analyzing the data.

- Data sources should be reviewed to determine completeness and accuracy.
- Review the Risk Registry every year to confirm that the assumptions are still correct.
- Review the risk assessment process every 3 years to identify and minimize other sources of uncertainty.

5.2.3 Determining Likelihood of Failure

Events that could lead to pipeline incidents and consequential impacts are identified in the ENGLP Risk Registry. The likelihood for these events to occur are discussed amongst a team of field technicians, engineering personnel, and through comparison counterpart ENGLP Gas Texas Integrity Management Plan, which lists frequencies of failure events. The likelihood of each identified failure is described within the Risk Registry.

5.2.4 Determining Consequence of Failure

Consequence analysis estimates the severity of the impacts of the event or sequence of events on the health and safety of people, the environment, availability of service, or other impacts included in the risk management program.

Consequence analysis considers not only the events that lead up to loss of pipeline containment, but other events (for instance, the probability of remotely operated isolation valve operating as intended) and considerations such as population density and distribution that could affect the severity of an event. Consequence analysis considers the following:

- Annual probability and scale of release incidents;
- Probability of casualty per release incident;
- Number of potential casualties per release incident;
- Potential number of customers or end-users affected per release incident;
- Potential extent of environmental damage per release incident; and,
- Potential economic cost per release incident.

5.2.5 Risk Estimation

Risk estimation is the process of combining frequency and severity and determining a risk value. Estimated frequency and the consequences for each of the various identified events or sequences of events are combined into a risk value for that event sequence.

A combination of the following variables may be used in estimating the consequences of an occurrence:

- Environmental receptors
- Population
- Business interruption

The risk assessment method is used to analyze risk factors and to evaluate areas of the system which pose a greater risk, where existing mitigation tactics may not be adequate to address the risk.

5.2.6 Risk Evaluation

Once a potential risk has been identified, risk assessment methods are used to predict the expected risk reduction or benefits that will be achieved. This process is captured within the ENGLP Risk Registry.

After the results of the risk assessment are available, the next step will examine the most significant risks on the system, as well as other opportunities to more efficiently control risks and determine what preventive actions might be desirable. The risk control and mitigation evaluation process may involve the following steps:

- Identification of risk control options that lower the likelihood of a pipeline system incident, reduce the consequences, or both (i.e., preventive activities).

- A systematic evaluation and comparison of those options to quantify the risk reduction impact of the proposed project.
- Selection and implementation of the optimum strategy for risk control.
- A tracking system for recommendations and follow-up actions.
- Risk estimation re-calculation after implementation and effectiveness review

5.2.7 Validation and Prioritization of Risks

Once the risk assessment method and process has been validated, the General Manager, ENGLP presents the results of the ENGLP Risk Registry to upper management for further review. Risks which are deemed to have a significant consequence may require further effort to review and scrutinize the mitigation methods.

5.2.8 Continuous Risk Assessment

Risk assessments as documented within the ENGLP Risk Registry will be reviewed once every 3 years to ensure that the process yields results consistent with the objectives of the Integrity Management Program. The method used to perform the risk assessment will be adjusted and improved with each use as more detailed and current information about the pipeline system becomes available.

5.3 Risk Reduction

The risk analysis and risk evaluation, as documented within the ENGLP Risk Registry, shall document the measures employed by ENGLP to reduce the identified risks to a threshold that ensure the residual mitigated risk is not significant. As described within the ENGLP Risk Registry, examples of risk mitigation measures are as follows:

- Inline inspection/pipeline pigging to measure wall thickness, metal loss, and to identify areas of the pipeline which show incongruities within the material, such as, cracks, deformation, strain detection and measurement inline inspection technologies;

- Cathodic protection monitoring; including induced AC current;
- Coating condition surveys;
- Pipeline leak surveys;
- Annual inspection using industry recognized inspection standards/techniques and maintenance of all above-ground facilities;
- Repair and replacement programs exist, as required; and
- Reduction in likelihood of external interference causing damage to pipeline systems through:
  - Participation in utility locate and municipal co-ordination programs,
  - Providing public and customer education and awareness campaigns to 'Call before you Dig',
  - Providing physical marking of critical infrastructure, and
  - Physically protecting exposed critical infrastructure with traffic berms and vehicle barriers.

For new construction activities, the pipeline materials and all components are received and inspected by a qualified inspector prior to use in construction activities. After field execution, the system is performance tested through a variety of measures including pressure testing, non-destructive examination of welds for steel lines, and component testing. The system is only brought online once the system is confirmed to have met all quality assurance and control criteria.

By following the mitigation measures listed above and within the ENGLP Risk Registry, the system is able to be maintained at a sufficiently low level of residual risk.

6.0 ENGLP Asset Management Overview

ENGLP has developed, and employed its own asset management planning process. This section of the Plan provides a high-level overview of ENGLP's asset management process.

ENGLP's asset management process is a systematic approach used to plan and optimize ongoing capital, operating and maintenance expenditures on the distribution system. Natural Gas distributors are capital intensive in nature and prudent capital investments and maintenance plans are essential to ensure the sustainability of the distribution network. ENGLP is continuing efforts to improve the information available to the asset management process for all major equipment.

ENGLP will implement an asset management framework consistent with ISO 55000 Standards for Asset Management and the more specific requirements of CSA Z662 Standard for Oil and Gas Pipeline Systems. The framework and asset management plans, founded on the principles of continuous improvement, will continue to evolve over time based on requirements and priorities.

ENGLP will continue to update its asset inventory and associated data, assess the infrastructure and refine its asset management plan. These activities will likely result in further refinement of the USP and associated projects, programs and priorities.

6.1 Overview of the Asset Planning Process

Through the asset management process, ENGLP endeavors to answer the following questions:

v. What is the current inventory of asset managed, what is the age and condition, and how much life remains?
vi. What are ratepayer's needs and expectations for natural gas service?
vii. Which assets are most critical to meeting the customer service goals and objectives?
viii. What are the linkages and trade-offs between capital and ongoing operations and maintenance spending?
ix. What is the most prudent investment strategy?

As it better understands its assets, ENGLP will begin implementing a more formalized asset management framework, and specific asset management strategies and plans, which optimize lifecycle cost and value to the ratepayer. In its asset management plan, ENGLP will draw on the expertise and experience developed from its affiliate companies that own regulated electrical, water and wastewater assets.

A complete and accurate asset registry, or inventory, is key to the process. As the utility continues to build upon the implemented Utility Management and Workflow Management software as well as GIS capabilities, it will better positioned for the future.

At its foundation, the asset management process is risk-based. ENGLP will proactively evaluate risk and criticality of the natural gas distribution assets and use this information in crafting maintenance and monitoring strategies. The utility will continue to assess and manage risks in accordance with ENGLP's risk management framework and in keeping with the more specific requirements of a System Integrity Management Program under CSA Z662.

Ongoing condition monitoring of assets allows the utility to measure and track the effectiveness of the asset management strategies implemented and is an important component of the System Integrity Management Program. ENGLP will continue and improve upon current condition monitoring practices and programs based on risk and consistent with industry accepted practices.

At a high level, this five step process summarizes ENGLP's asset planning process.

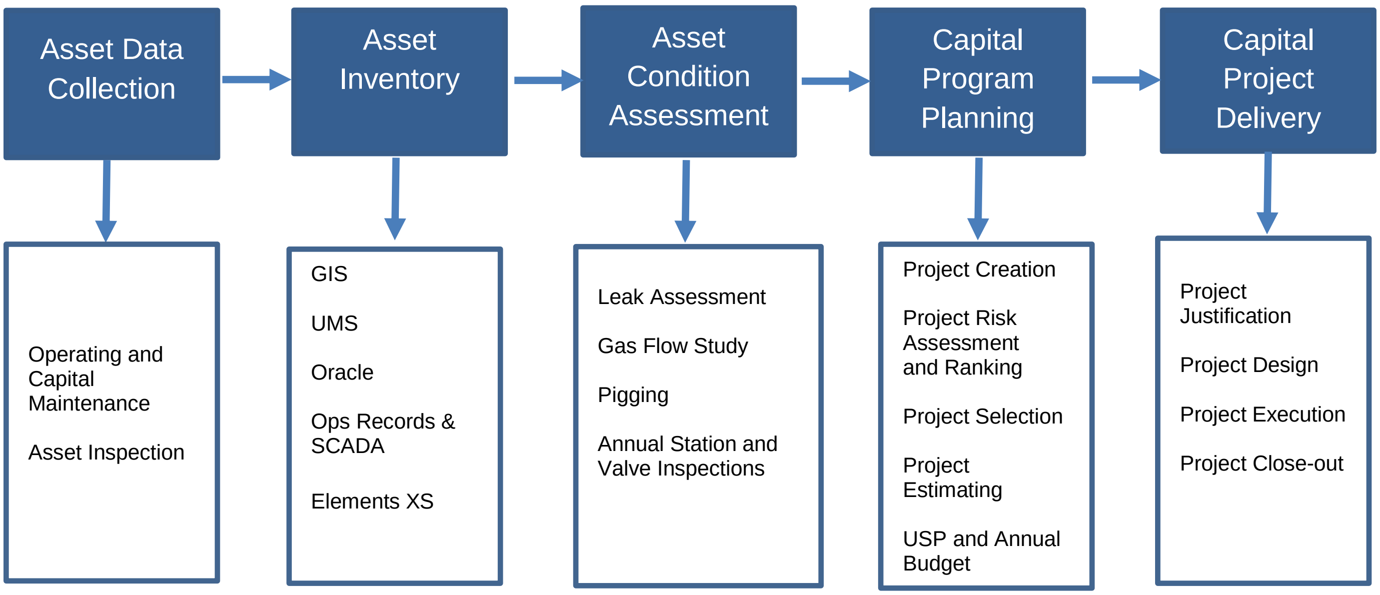


Figure VIII – ENGLP Asset Management Planning Cycle

6.1.1 Step 1: Asset Data Collection

The first element of the ENGLP asset management plan is to collect data on the assets. Data is collected through the execution of annual maintenance and inspections tasks, or anytime the asset is engaged through ongoing operational or capital projects. The asset data collection identities the key assets and classifies them into a hierarchy. This is used to establish an inventory of assets which represents a count of the key assets within the asset hierarchy. Lastly, information on inventory of assets is supported by details on each asset class, such as age, year of install, length etc.

6.1.2 Step 2: Asset Inventory

The second component focuses on the compilation of asset data. At ENGLP, the asset register is not a singular information source; rather, it consists of digital and paper records located separately and managed by specific individuals. The Asset Register comprises four primary elements: the ESRI Geographical Information System (GIS), the Oracle financial management system, the Customer Information System (CIS/UMS), and Operations Records databases/files.

The GIS plays a central role in the Asset Register, housing attribute information (such as age and material) for all non-general plant assets such as mains, services, valves, and service end-points. ENGLP's GIS was introduced in 2021, and our long-term plan involves progressively transferring and linking more asset information from Operations paper files and various electronic databases to the GIS. The GIS seamlessly interfaces with ElementsXS software, enabling users to view, create or complete work orders, and access records associated with each asset. The accessibility of the GIS to the entire team contributes to ongoing improvement in data accuracy and enhances the significance of various roles across all departments.

General Plant assets (excluding land and buildings) are managed separately through the Oracle financial management system. In conjunction with the GIS and ElementsXS, the UMS (Utility Management Solution) is utilized to delve deeper into the details and usage patterns within the system, to examine customer usage, and verify meter history. Asset inspection and maintenance data is currently being organized and recorded through ElementsXS and excel files. Future recording of assets inspections and condition assessment is planned to be introduced into the GIS environment, ultimately eliminating the use of excel spreadsheets and paper forms.

Asset Register			
Asset register component	**Owner/Location**	**Asset information**	**Information media**
ESRI GIS	Operations	- Asset location (pipe GPS coordinates) - All attributes (age, size, length)	- Digital database composed of multiple map layers of assets
Oracle Financial Management System	Accounting/Regulatory	- IFRS and Regulatory asset value - Asset useful life studies - Contributed capital	Digital Database
	Accounting/Regulatory	Distribution Plant (bulk GL) - Purchase history - Depreciation amounts General Plant - Purchase history - Depreciation amounts (land, buildings, hardware, software, fleet)	Digital Database
UMS/CIS	Customer Service	- Meter information (physical attributes, consumption, etc.)	Digital Database;
Operations Records	Operations	Maintenance Records	Digital and Paper Files
	Operations	Inspection Records	Digital Files
	Operations	Asset utilization records	Digital and Paper Files
	Operations	Fleet history	Digital and Paper Files

		Tool, test equipment history	
	Operations	- Work order history - As-built information linked to pipeline records	Digital Database
ElementsXS			

6.1.3 Step 3: Asset Condition Assessment and Monitoring

The third element is the asset condition assessment. The primary factor in determining the condition of underground pipe is the age of the pipe. In addition, above ground inspections are done through leak surveys and surface corrosion surveys. This data is correlated with the age of the asset to form the asset condition. For above ground assets such as regulating or valve stations, field inspections are completed on an annual basis.

ENGLP reduces the frequency of failure and damage incidents associate with improper operation or control system malfunction through:

- Enhanced personnel training, employee evaluation, and worksite assessments;
- Improved pipeline system control and monitoring methods;
- Modified operating and maintenance practices; and
- Improvements or modifications to piping and equipment.

ENGLP performs the above through application of the following controls:

- Enhanced personnel training is provided by TSSA certification and training, with all technicians maintaining a minimum Gas Tech-2 level certification, with several obtaining the Gas Tech-1 certification
- ENGLP employees perform worksite assessments through filling out a Safe Work Plan prior to beginning work at each new worksite location and activity.
- Steel pipeline segments have enhanced corrosion monitoring and control which is reviewed annually.

- SCADA pressure monitoring is installed throughout the system which allows operations personnel to remotely and continuously monitor system pressures, including responding to alarms, if applicable.

Further, ENGLP reduces the frequency of failure and damage incidents associated with imperfections (e.g. metal loss, cracking, and material, manufacturing, and construction defects) described in the Table below:

Temporary or permanent reductions in the established operating pressure	Not an option current used
Close-interval surveys	Conduct annual leak surveys, cathodic protection read survey, depth of cover survey, and overall leak inspection survey for both steel and plastic piping and performs repairs according to a leak severity / classification method.
Coating assessment surveys	Where an opportunity presents itself (e.g., during an excavation), the pipe is inspected for external corrosion and coating assessment.
Improved performance of cathodic protection systems	Cathodic protection is applied on ENGLP steel pipeline segments. Annual cathodic protection surveys are completed and where there is an indication that insufficient cathodic protection exists, the contractor provides a recommended solution.
Repair or rehabilitation of external coatings	Performed as required during inspection activities.
Improved internal corrosion mitigation and monitoring methods (see CSA Z662-15 Clauses 9.10.2 and 9.10.3)	Annual cathodic protection surveys are completed

Effective pressure cycle management or reduction program (e.g., optimized pipeline system design and supply scheduling)	Pressure cycling is not an issue within the ENGLP network, thus its management is not deemed required by the utility.
In-line inspection programs	○ In-line inspection programs exist on select segments of the steel system piping of diameter 6” and greater. ○ Cleaning pigs are run at frequent intervals. Depending on the residue that is removed, the team completing the work in the field assesses the required number of pigs to be run and next interval of cleaning. ○ Caliper / gauge plate tools and smart tools are also run at intervals of 1 in 10 years to assess the pipeline for any constrictions and to measure the pipe wall thickness. Based on the results, the team assess if a repair plan is required.
Pressure testing as specified in CSA Z662-15 Clause 10.3.8	The ENGLP pipeline network undergoes pressure testing prior to introduction of service fluids.
Improved quality measures for manufacturing, design, construction, and operation	All piping material is inspected for appropriate sizing and material prior to installation. Damaged piping is removed and not used in the field.
Assessment, repair, rehabilitation, and replacement programs.	These are completed as required, and as the needs are identified.

Prioritization and scheduling of activities related to pipeline integrity management follows the philosophy described in the Table below:

Immediate Action Required	Includes areas that are likely to have ongoing decline in integrity and that, when coupled with integrity measures noted in previous surveys, may pose an immediate threat.	Example 1: Corrosion activity that when couple with prior corrosion, may pose an immediate threat. Example 2: A defect is noted during in-line inspection activities that is of a substantial size or concern, especially if located within a high consequence area. Example 3: A leak is observed that is sufficient in size to cause immediate concern, or is located in an area likely to have an ignition source present.
Scheduled Action Required	Includes indications that may have ongoing decline in integrity but that, when coupled with prior integrity history, may not pose an immediate threat to the pipeline under normal operating conditions	Example: in-line inspection has determined an area of the pipeline that has reduced in wall thickness since the baseline, but based on the calculated rate of wall thinning, the area does not pose an immediate threat but should still be replaced/repaired according to an appropriate recommended schedule
Suitable for Monitoring	Includes indications that the pipeline operator considers inactive or as having the lowest likelihood of ongoing or prior integrity measure.	Example: corrosion monitoring has indicated that an area of the pipeline has experienced a minor amount of corrosion as found during an annual survey. The contractor who executed the annual corrosion survey recommends the area to be ‘monitor only’. ENGLP notes the area and ensures to compare the corrosion

		monitoring results during the following year's survey.

From a records keeping perspective, ENGLP will keep records of the following performance measures:

i. The number of pipeline leaks, eliminated or repaired, based on types / causes;
ii. The number of excavation damages;
iii. The number of locates received and completed within the required 5 days based on legislated requirement;
iv. Assets inspections and maintenance completed in a timely fashion; the types of assets inspected and maintained will include the following;

- Mercury Calibrations
- Station Maintenance
- PFM Maintenance
- Poly Valve Maintenance
- Annual Pipeline Leak Survey
- Annual Building Survey
- Annual Corrosion Survey
- Annual Depth of Cover Survey

Each performance measure is tracked currently in the GIS platform in Elements. The list of underground asset performance will be tracked, to ensure the effectiveness of the program is focused on areas of risk to the integrity of ENGLP operations.

Overall, the below table summarizes the integrity management activities and scheduled adhered to within the ENGLP system:

Integrity Activity Description	Frequency
Maintenance inspection (all above ground utilities), inspection survey (Hetek), cathodic protection read survey, depth and cover survey, overall system leak survey (plastic and steel systems)	Annually
Pigging and cleaning activities, maintenance/sweeper pigs	1 in 4 years, or as required*
In-line inspection activities (using in-line tools to measure soil movement, pipe wall thickness, deformities or imperfections as well as detect metal loss, corrosion and pitting in the pipeline)	1 in 10 years, or as required*
Repair and replacement programs	As required*

*As required is based on experience of the Operations Engineer or General Manager, and takes into consideration the factors listed in CSA Z662-19 N.11.2, which are as follows:

- Known conditions, damage, or imperfections (e.g., corrosion or manufacturing imperfections) that might lead to failure incidents;
- The potential growth of any damage or imperfections;
- The options selected to control identified hazards (see CSA Z662-19 Clause N.1.8 and Section 7 of this IMP);
- Method of inspections and analyses to refine the estimates of risk (see CSA Z662-19 Clause N.1.9.6 and Section 8 of this IMP);
- The options selected to reduce the estimated risk level (see CSA Z662-19 Clauses N.9.4 and N.10, Annex B and Section 8 of this IMP);
- Inspections, testing, patrols, and monitoring (see CSA Z662-19 Clause N.1.12 and Section 9 of this IMP);
- Recommendations from previous integrity reviews and activities;

- The failure and damage incident history of the operating company;
- The failure and damage incident experience of the industry; and
- The use of either direct or indirect inspection activities or a combination of both.

ENGLP engages with Cornerstone Energy Services to complete a system integrity analysis of its natural gas distribution utility. Cornerstone creates a steady-state hydraulic model of the system, reviews the predicted system conditions under the current peak gas demand, and predicts future peak demands given predicted growths. The objectives are to identify constraints within the system that would impact the utility's ability to provide reliable natural gas service to current and future customers, and identify and evaluate possible system reinforcement options to resolve these issues.

Lastly, ENGLP also completes its own condition assessment of its vehicle fleet. The Annual Fleet Replacement Program accounts for the replacement of fleet, including light trucks and vans, medium-duty trucks and construction equipment. Existing fleet which have been assessed at economic end-of -life units are to be traded for new fleet units. Condition assessments have been completed on all fleet vehicles to determine need for trade. Condition assessments include factors such as age, mileage, engine hours, type of service (harsh, offroad, paved), reliability history, maintenance cost history, interior/exterior condition (ex: rusting), and other as necessary. Optimal timing includes spreading out the capital costs over the capital USP period and also to prolong the life of the vehicle to the furthest extent possible to reduce the rate impact.

6.1.4 Step 4: Capital Program Planning

The fourth element is the development of the capital program. ENGLP completes an annual budget and conducts a multi-year planning process that includes forecast of volumes, revenues, capital investments and operating and maintenance costs. The budgeting process allows ENGLP to execute on its strategic priorities and ensures safe and reliable operations are maintained. Further, for every rate application, ENGLP develops and publishes its 5-year capital program, presented through the USP.

The capital program planning element has five steps including Project/Program Creation, Project/Program Risk Assessment and Ranking, Project Selection and Estimation, Annual Budget

Planning and Capital Project Delivery. Each of the steps have been described in detail in the USP Section 4.0

ENGLP follows EPCOR's organization project management process to deliver capital projects. Prior to finalizing the annual budget or approving any spend, a project justification is completed. This is a more focused review of the risk assessment and cost benefit analysis of the project. This requires Senior Vice President Approval. This is followed by Project Design where a more detailed estimate, technical design and schedule are developed. Project execution is tracked against the budget and schedule. Finally, the project is financially closed out following required accounting principles.

7.0 ENGLP Asset Management Requirements

The Asset Plan establishes the requirements and estimates the related capital expenditures to support four primary kinds of asset-related investments - Customer Growth, System Reinforcements, System Integrity & Reliability including work on the dedicated 6inch steel line serving the Integrated Grain Processors Co-op customer.

7.1 Customer Growth

ENGLP delivers safe and reliable natural gas to approximately ten thousand customers which is forecasted to grow over the 5-year period of this Asset Management Plan. The operations services residential, commercial, industrial and agricultural customers within its franchise areas. Growth consists of the addition of new customers, customers converting from another fuel source to natural gas as well as upgrades to existing equipment's or services to accommodate load growth.

The Growth capital expenditure requirements for asset installation is based on customer growth forecast over the next 2023-2028 period. Capital investments such as material and labour costs are required to support the new customer connections. ENGLP projected customer growth forecast over the next 5-year period through information received from developers and municipalities. On average, the annual growth rate for each of the towns within the Aylmer distribution system was 2%. A town load represents consolidated loads of all the customers in corresponding town's district. Capital spending for non-town (rural) loads are assessed and analyzed on an individual basis. This involves analysis of whether new distribution mains or reinforcements to existing mains are required to service these loads.

Table 5 below summarizes detailed load allocations for each of town loads (per district regulator station) in the Aylmer distribution system.

Table 5: Load Allocations for town loads in Aylmer distribution system (2023, 2028)

	Town Loads (m3/hour)	
Towns	**2023 Estimate**	**2028 Estimate**
Aylmer East	902	984
Aylmer Beech St	1,430	1,560
Aylmer Roger-Talbot	385	420
Aylmer Bradley Creek	385	420
Aylmer Hacienda	385	420
Aylmer (Total)	3,488	3,805
Belmont (Total)	1,050	1,146
Brownsville - 3810	132	144
Brownsville - South	121	132
Brownsville (Total)	252	275
Nilestown (Total)	175	192
Port Burwell East	279	305
Port Burwell West	279	305
Port Burwell (Total)	560	610
Port Bruce 1st	132	144
Port Bruce 2nd	132	144
Port Bruce (Total)	264	288
Springfield (Total)	410	448
Straffordville (Total)	263	287
Vienna (Total)	263	287

7.2 Distribution System Reinforcement

ENGLP conducts reinforcement projects in its system to maintain minimum system pressures for demand of gas to be met on design day conditions. These projects involve the installation of new gas infrastructure or modifications to existing gas assets to maintain system pressure, capacity and meet growth demands.

ENGLP conducts annual hydraulic simulations of the natural gas system using Cornerstone Energy Services. The hydraulic model uses pressure and flow measurement on the system during peak conditions experienced for the year. For one off large volume customers, hourly data is usually available and included within the analysis. The objective of the network design is to meet anticipated peak at temperature dependent design conditions. Load additions are modeled based on the design temperature. Reinforcements are based on the system's ability to meet minimum system pressures based on forecasted loads at key locations. This is based on 5-year forecasted growth to ensure the system has the security of supply and reliability needs to meet gas demands.

The ENGLP 2028 system integrity simulations revealed potential gas supply shortcomings to meet prospective demand. Several options for increased delivery volume through Bayham, Dorchester and Lakeview stations, along with relevant piping upgrades, were analyzed and simulated. A list of proposed capital improvement projects to meet the 2028 demands have been developed, and discussed in the Utility System Plan. Detailed business case justifications are provided for each project separately as part of the USP.

7.3 System Integrity and Reliability (Distribution Assets and Plastic Pipe)

ENGLP has a combined inspection and maintenance practice for field assets. Asset inspection and maintenance is designed to optimize the asset lifecycle until such time that the asset has reached a condition requiring refurbishment or replacement.

ENGLP's operations and maintenance strategy is to minimize reactive and emergency-type work through efficient operations and an effective planned maintenance program, including predictive and preventative actions. ENGLP's customer responsiveness and system reliability are monitored continually to ensure that its maintenance strategy is effective. This effort is coordinated with ENGLP's capital project work so that where maintenance programs have identified matters which require capital investments, ENGLP may adjust its capital spending priorities to address those matters. ENGLP constantly evaluates its maintenance data to adjust predictive and preventative actions with the ultimate objective being to reduce and minimize any emergency maintenance work.

Recently, ENGLP has utilized GIS and SCADA to provide a better overall understanding of its assets that will lead to more efficient and optimized design, maintenance and investment activities going forward. Inspection, maintenance and testing data will be input into the GIS as attribute information for each piece of plan. Increased and accurate operating data will be collected through GIS and be made available for engineering analysis and service quality reporting.

ENGLP's Integrity Management Program contributes to extending the useful life of assets by identifying condition issues prior to occurrences of incidents. The weekly, monthly and annual inspection activities reduces the probability of pipeline failures and unplanned asset integrity issues. The program includes procedures to monitor for conditions that can lead to failures and includes a description of ENGLP's commitment to assess risks, identify risk reduction approaches and monitor results. ENGLP is constantly looking to update its IMP to ensure condition issues are identified and mitigated continuously using the Plan-Do-Check-Act methodology.

The condition methodology for distribution piping is through annual maintenance programs (Leak Surveys and Cathodic Protection Surveys) to monitor asset conditions. Steel distribution pipes are prone to internal and external corrosion when coatings and cathodic protection is lacking and go through the annual leak and cathodic protection surveys. Steel mains under bridge crossings and plastic pipe in casing can also be exposed to road salt and seasonal ground movements that can affect its integrity over time. Many such casings can lack test points which prevents monitoring. ENGLP ensures to do monthly cathodic protection checks on bridge/railway crossings in the distribution system.

Overall, ENGLP's inspection and maintenance program is summarized in the table below:

Table 6: ENGLP Inspection and Maintenance Program

Program	Frequency
Gate and Regulating Stations	• Inspected Annually • No more than 18 months wait time for inspection of stations
Above Ground Valves	• Inspected Annually
Poly-Valves (underground valves)	• Inspected Annually
Regulatory and Filter Inspections on Local Production Wells	• Inspected Annually (ENGLP side)
Electronic Volume Correctors at Large Customer Station	• Calibration Checks Annually (Temperature, Pressure)
Pressure Factor Metering (PFM) Regulators	• Tobacco Customers – Inspected Annually • 10psi PFM's – Inspected once every 2 years • 5psi and 2psi PFM's – Inspected once every 3 years
Station Odorant Checks	• District Stations Inspected Monthly • Lakeview Station Inspected Weekly • RNG Station Inspected Weekly • Local Production Wells Inspected Weekly
Dew Point Checks	• Lakeview and RNG Station Inspected Weekly
Cathodic Protection Checks	• Bridge/Railway Crossings Inspected Monthly
Hetek Leak Survey	• Conducted Annually on the Aylmer Distribution System and Dedicated 6inch Steel IGPC Pipeline
Public Building Survey	• Conducted Annually in the winter time period to check for underground leaks migrating to public buildings

Appendix 2 – ENGLP Aylmer System Integrity Study

EPCOR AYLMER SYSTEM INTEGRITY STUDY

Revision No.	Revision Date	Approved	Effective Date
A	06/12/23	SIP	06/12/23
B	20/12/23	SIP	20/12/23

LICENSED PROFESSIONAL ENGINEER
2023
S. I. PLIASSOUNOV
20/12
PROVINCE OF ONTARIO

Cornerstone
Energy Services

2 ROBERT SPECK PARKWAY

MISSISSAUGA, ONTARIO
L4Z1H8

TABLE OF CONTENTS

1 EXECUTIVE SUMMARY

The 2023 system integrity computer simulations indicate healthy capacity except for two potentially problematic areas with conceivably deficient system pressure. Both those areas can be improved via a piping upgrade. The 2028 system integrity simulations revealed potential gas supply shortcomings to meet prospective demand. Several options for increased delivery volume through Byham, Dorchester and Lakeview stations, along with relevant piping upgrade, were analyzed and simulated. A list of proposed capital improvement projects to meet the 2028 demands has been developed. The addition of a prospective power generation facility at 9608 Carter Road represents a significant increase in system demand. This load is best served by additional supply capacity at either Dorchester or Bayham's station with corresponding improvement of the existing piping.

2 INTRODUCTION

ENGLP has contracted Cornerstone to perform a system integrity study of the Aylmer natural gas distribution system as it stands in 2023. The project scope also includes estimation of the system integrity according to the 2028 growth projection developed by ENGLP. The purpose of this study is to identify requirements for system enhancement to meet load growth and to identify projects that will provide that enhancement.

The ENGLP Aylmer system is a local distribution company (LDC) that delivers natural gas in Southern Ontario to approximately 9,000 customers. The service territory extends south from Highway 401 to the shores of Lake Erie. In addition to the Town of Aylmer it services the surrounding region with the towns of Brownsville, Straffordville, Vienna, Port Burwell, Port Bruce, Springfield, Belmont, and Nilestown.

The system consists of more than 700,000 meters of distribution mains which are fed by nine gate stations (Bradley Ave, Putnam, Harrietsville, Belmont, Brownsville, Bayham, Eden, Lakeview, and North Walsingham) and three sets of natural gas wells in the southern and southeastern part of the system.

3 BACKGROUND

Cornerstone performed similar integrity studies of this distribution system in 2018 and 2022. For the initial development of the GasWorks model in 2018 ENGLP provided CAD and GIS shape files and a database of attributes for each piping segment in the system. Based on this data Cornerstone developed a model in the distribution modeling program GASWorks version 10.0 to analyze the system performance. The model was validated through cross-examination of ENGLP system documentation, CAD records, system map, databases, and Operation personnel input. Relevant details regarding the model development and calibration can be found in the 2018 Study Cornerstone report.

The 2018 GasWorks model was built on the following fundamental approach. All the clients were grouped into two types of load points – combined town loads and smaller separate customers outside the towns. A town load node represents consolidated loads of all the customers in corresponding town (instead of having hundreds of individual load points throughout the town's model it was possible to simplify the representation greatly by using only a few nodes for each town). Those remaining customers outside the towns (branded as "rural customers") are in turn classified as either firm or interruptible (seasonal) ones. A typical interruptible customer would be a grain dryer who may not need the ability to dry their crops in the middle of January. This model choice was made to provide the ability turn such interruptible customer's gas loads on and off when modeling the hydraulic performance of the system at different times of the year. However, that model simplification advantage evolved at the expense of its accuracy, which required extensive calibration. Nevertheless, those model shortcomings have been shown to be acceptable through validation of the simulation results. Please refer to the 2018 Study Cornerstone report for more details.

The 2022 study used the 2018 model, updated by inserting with added customers, increased town loads and recent system piping configuration changes.

When the 2023 and 2028 simulation and the project scopes were discussed, it was the team decision to use the existing 2022 GasWorks model as the baseline.

ENGLP acknowledged and accepted the existing GasWork model's limitations. Correspondingly, the focus was on determination of the differences between 2022 and 2023/2028 (the loads, new and prospective customers, recent piping layout changes etc.).

4 2023 MODEL DETAILS

The 2023 model uses the 10.2 Gas Works version. The settings and the assumptions are the same as the 2018 and 2022 models had:

- Hydraulic efficiency: .95
- Elevation: 235ft
- Gas average temperature: 15 deg C
- Specific Gravity: 0.583
- Gas Viscosity: 7.2x10-6 lb m/ft-sec
- Heating value: 1027 btu/cf
- Specific heat ratio: 1.31
- Flow Equation – IGT Improved

The differences between 2022 and 2023 with respect to the new/added customers was determined using ENGLP billing data. The list of new customers was compiled by ENGLP with tagged rural clients and was analyzed by Cornerstone. This list included all kinds of customers – rural and those within town borders, interruptible and firm ones. Sorting them by actual consumption revealed that the top 70 new customers combine 82% of that list's total consumption (the 2023 surcharge compared to 2022). Correspondingly these 70 customers have been selected to be added to the 2023 model as they represent the bulk of the demand increase. The total hourly consumption rate for these 70 is approximately 90 m3/h. Thus, less than 20 m3/h in the 2023 surcharge was deliberately neglected, which is less than 0.2% of the total 2023 demands.

Further, there are 29 customers in the top 70 list, which are located withing towns' district regulator stations area. Their total consumption is 35.2 m3/h, which is a significant fraction of the 2023 additions. As with all customers located in town, fed from the 30 PSIG systems behind district regulators, it is not clear how those loads are distributed among the several district regulators feeding the town. Aylmer Town for example, has five district regulators feeding its 30 PSIG distribution system. All new in-town customers loads were assigned to the district regulator that is geographically closest to the customer.

In the 2023 GasWorks model these 70 new customers can be easily recognized by the Location ID in the customer description (the 2022 customers have this field empty).

The general town loads for the 2023 model are based on the 2018 data, which have been increased by the average annual growth rate of 2%. A town load node represents consolidated loads of all the customers in corresponding town's district. In the framework of our models those town loads are allocated, subjectively, to related district regulator stations. See Table 1 for detailed loads allocations per each district regulator station.

Table 1. Town Loads Allocations

Subdivisions/Districts	Town Load (m3/h)		
	2018 data	2023 estimate (2018 x 1.1)	2028 estimate (2018 x 1.2)
Aylmer East	820	902	984
Aylmer Beech St	900	990	1080
Aylmer Roger-Talbot	350	385	420
Aylmer Bradley Creek	550	605	660
Aylmer Hacienda	550	605	660
Total for Aylmer	**3170**	**3487**	**3804**
Belmont	537	590.7	644.4
Belmonth North via Nielestown	418	459.8	501.6
Total Belmont	**955**	**1050.5**	**1146**
Brownsville -3810	120	132	144
Brownsville_S	110	121	132
Total Brownsville	**230**	**253**	**276**
Nilestown	**159**	**175**	**191**
Port Burwell East	254	279	305
Port Burwell West	254	279	305
Total Port Burwell	**508**	**558.8**	**609.6**
		0	0
Port Bruce 1st	120	132	144
Port Bruce 2nd	120	132	144
Total Port Bruce	**240**	**264**	**288**
Springfield , total	**373**	**410.3**	**447.6**
Straffordville total	**239**	**262.9**	**286.8**
Vienna , total	**239**	**262.9**	**286.8**

According to the ENGLP team there were a few minor piping changes and upgrades since 2022. All of them have been captured in the 2023 model based on communications with ENGLP Operational personnel and shape files provided by ENGLP. The following changes and upgrades incorporated in the 2023 model:

- Nilestown main upgrade to 4" size
- South Belmont regulator relocation and 4" shortcut
- New shortcut on Avon Drive toward Putnam Road

- Imperial Road main toward Aylmer – upgrade to 4" size
- Harrietsville and Lewis roads intersection minor correction
- Minor corrections from Walsingham station and near intersection.

While working on the 2023 model tuning it was noticed that its calibration is performed easier and more accurately when the Nilestown station and northern Belmont district are considered as a separate subsystem. This is another difference between the 2022 and the 2023 models. The 2023 model comprises two subsystems: the first one is Nilestown station feeding northern Belmont and Nilestown districts and, the other one – all the remaining districts and stations.

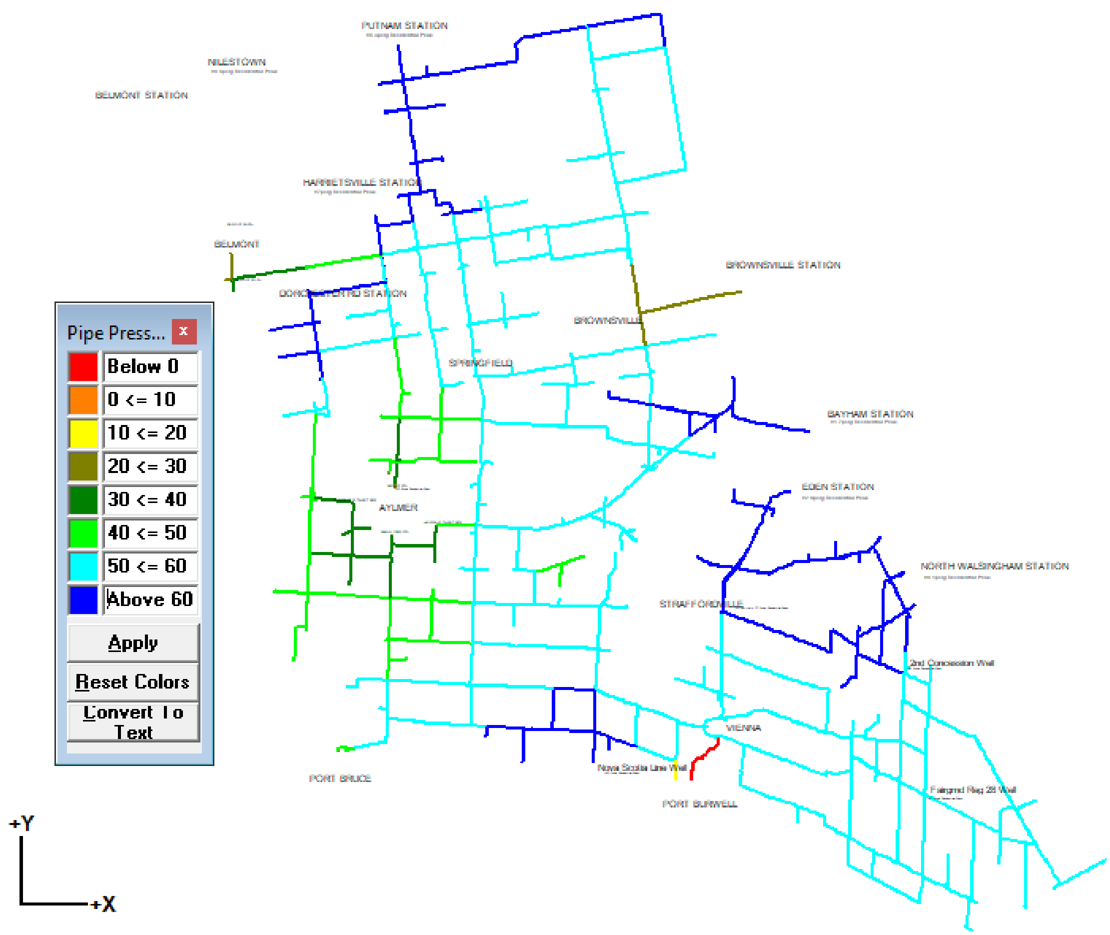
5 2023 SIMULATION RESULTS

Cornerstone performed the 2023 system integrity simulations for two different load cases: January peak flows/loads and a fall flows/load. Peak flows were determined by ENGLP. The supply stations maximum flows as registered during 2021-2022 and 2022-2023 heating seasons were used directly for corresponding station calibration in the model. The January 2023 consumption data were the base to determine the flows for the top 70 customers added for 2023. The remaining loads/flows were a carry-over from the 2018 and 2022 models. The 2023 town loads were increased by 10% compared to 2018 using the abovementioned 2% annual growth rate. The flows/loads for the existing out of town customers remain the same as in the 2018 model. The difference between January load case and fall load case is the number of seasonal (interruptible) rural customers. The January load case has no seasonal customers accounted (all the interruptible customers are switched off). The fall case has all the seasonal customers switched on with their full (not adjusted) flows and the remaining customers and town loads/flows are adjustable according to the design factor. The design factor allows to reduce firm customers' consumption flows to consider mild fall weather conditions if necessary. For the 2023 Fall loading case the design factor was 1.0, i.e. 100% of January firm customers' flows was used in that simulation.

The Nilestown and northern Belmont subsystem demonstrated healthy pressure and flows distribution throughout the whole subsystem. Cornerstone did not identify any potential problem for the 2023 integrity simulation and for potential supply and demand increase in there to up to 50% compared to the 2023 level.

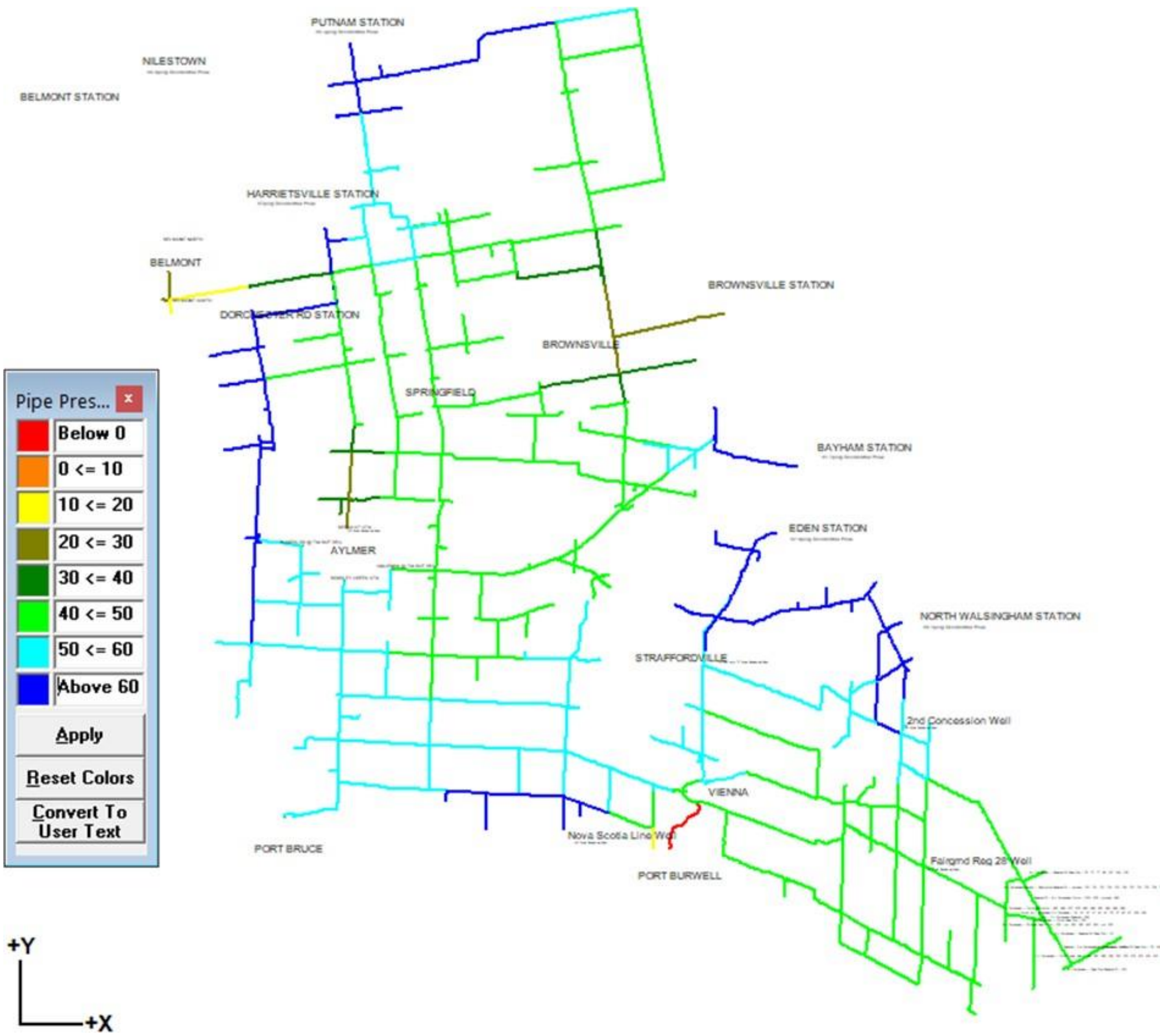
For the remaining part (the subsystem without Nilestown and northern Belmont) a few potential issues have been identified. Refer to Fig 1 and Fig 2 for system pressure distribution details.

Fig 1. 2023 January Loading Case Pressure Distribution Map



The January pressure map suggested at least one potential problem. These are both the 2” mains to Port Burwell, behind the district regulators, operating at 30 PSIG.

Fig 2. 2023 Fall Loading Case Pressure Distribution Map, Design Factor 1.0



The fall case suggested two more potentially problematic areas with possible low pressure. The 3" main going toward South Belmont along Yorke Street could have insufficient pressure if the January peak flow were combined with all the interruptible customers full consumption. Same extreme conditions indicate possible pressure issue in the 4" main feeding the Aylmer Beach Street district regulator station.

At the same time, we noticed that simulated pressure numbers on these (Aylmer and Belmont) potentially problematic spots are sensitive to the model calibration. Several iterations to recalibrate the model according to the actual (ENGLP reported) supply stations flows revealed that this Aylmer district potential low pressure should be attributed to the model inaccuracy. However, the Belmont district most likely may indicate a potential problem. Note, the Belmont bound 3" main low pressure was noticed only when the loads are adjusted above 80% (the design factor 0.8) which should indicate healthy pressure distribution when the flows are not extreme.

Cornerstone decided to examine the southern Belmont main and the Port Burwell ones in greater detail as both may need a capital improvement project. See section 7.1 for greater details.

6 2028 MODEL DETAILS AND SIMULATION RESULTS

The 2028 model is different compared with the 2023 one only by the number of customers and by increased towns' loads.

The town loads were increased using same 2% annual growth rate – basically the 2018 figures have been multiplied by the factor 1.2 as shown in Table 1.

There are only 6 prospective customers added to the 2028 model compared to 2023. These customers were chosen for addition to the model by ENGLP. All the remaining out-of-town customers' loads (both the seasonal and steady ones) are assumed to be the same as in 2018.

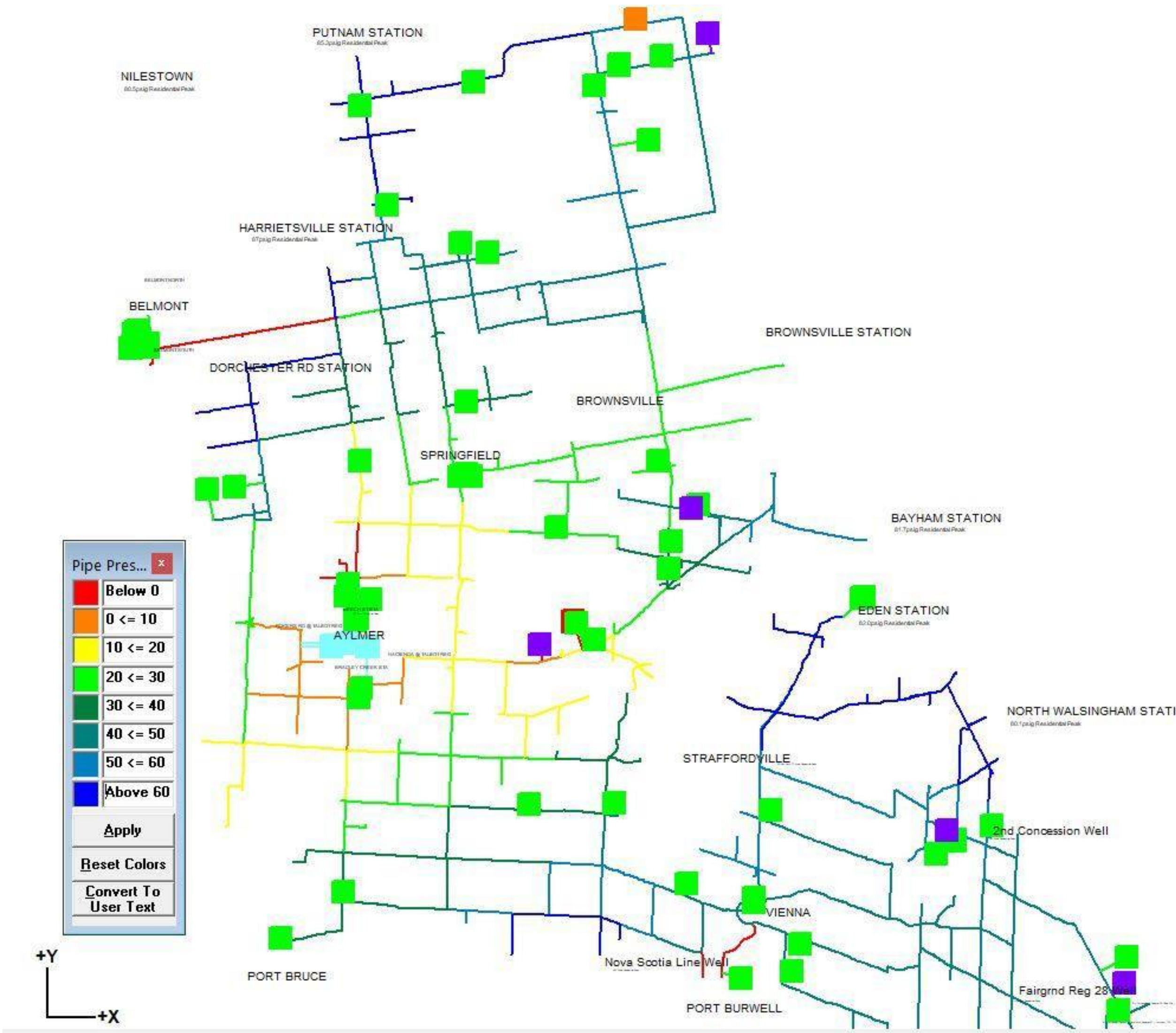
Those prospective 2028 customers and their loads are as follows:

- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]

Total projected (additional to the 2023 level) flow for these 6 new customers is 3,821.2 m^3/h, which is approximately 33% increase compared to the 2023 total load of the January case. Note that there is only one new seasonal (interruptible) customer assumed. Therefore, the additional load of 2,461.8 m3/h is not interruptible, which is roughly 20% increase compared to the January 2023 case demands.

Simulation of 2028 January case revealed significant pressure distribution degradation compared to the 2023 January results. The whole of Aylmer and some surrounding districts of the system were identified as problematic in addition to previously observed Belmont and Port Burwell areas. See Fig. 3 for greater details, 5 purple squares identify the locations of those abovementioned prospective customers except Aylmer Industrial Park.

Fig 3. 2028 January Loading Case Pressure Distribution Map



Obviously, the abovementioned increase of the 2028 demands made that impact. Moreover, the demand for the proposed 9608 Carter Road power generating facility is becoming critical. See Fig 4 for greater details, the 9608 Carter Road is indicated by a short gray arrow. If that only customer was switched off, then the pressure distribution map would be much better. Fig 4 also has two more prospective customers identified: the Aylmer Industrial Park location shown by short red arrow and large Greenhouse customer – by black one.

Fig 4. 2028 January Loading Case Pressure Distribution Map without 9608 Carter Rd. Facility Load

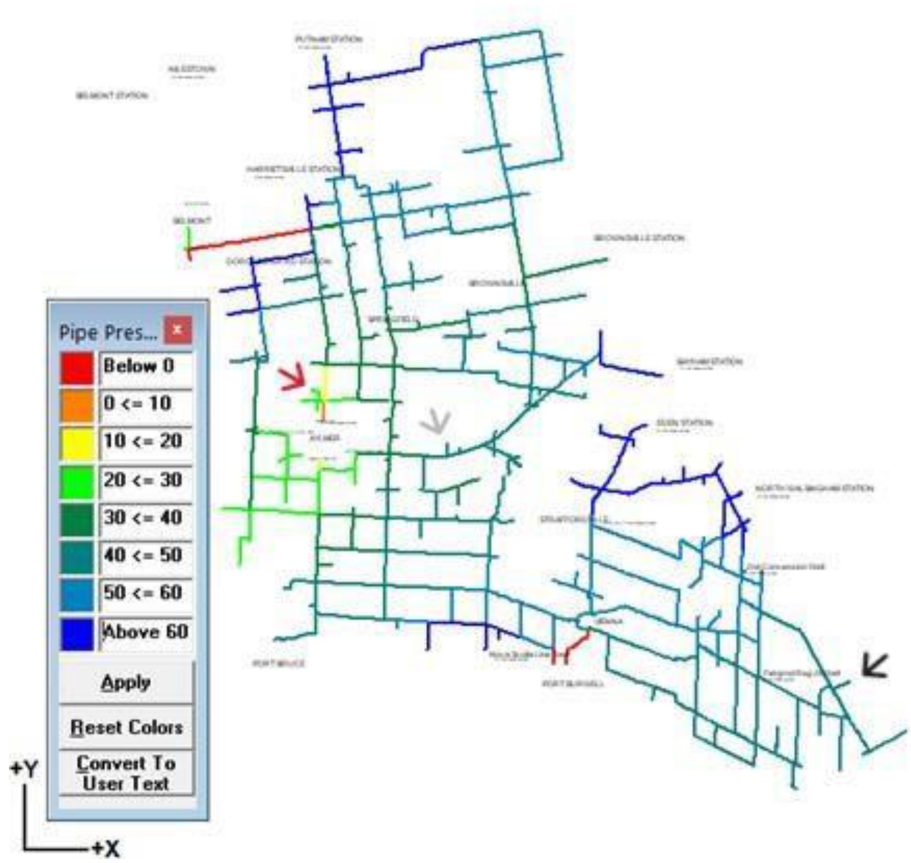


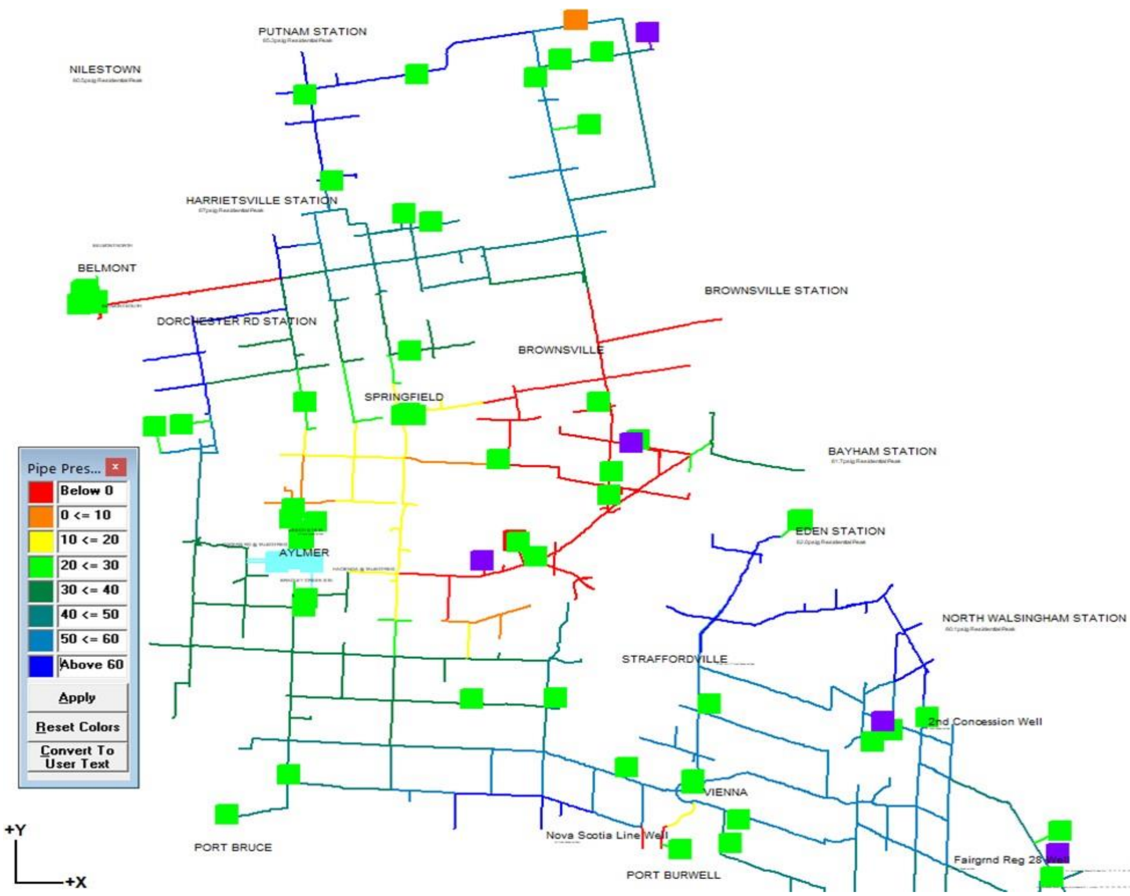
Table 2 summarized the flows balance for best calibrated simulation runs of the 2028 January and fall cases. Calibration of the model was somewhat challenging, and we were not able to replicate exact combinations of the pressures and flows reported by ENGLP as the base numbers in 2022-2023. Essentially during the model calibration, we eventually prescribed the flows at 4 most affected supply stations (Dorchester, Harrietsville, Putnam and Bayham) and then targeted reasonably practical for the existing system pressures to get to the reported figures as close as reasonably possible. The flow simulation results which exceeded available contractual limits are shown in red in Table 2. Note, Table 2 results assume Large Agricultural demand of 161.6 m^3/h.

There is one important outcome. Even with sufficient supply flow (when the 9608

Carter Rd prospective client is off) there are still 3 areas with potentially low pressure.

Simulations of 2028 fall case support that conclusion. When the demand is balanced with available gas supply through the design factor 0.75 (only 75% of the steady customers' load and full load of the seasonal customers) the pressure distribution map is not healthy at all. Fig 5 demonstrates that in addition to previously identified problematic areas the whole part of the system east of Aylmer would have negative pressure.

Fig 5. 2028 Fall Loading Case Pressure Distribution Map with Break-even Flows (Design Factor 0.75)



Obviously in case of full load from both firm and interruptible customers (notional fall case with the design factor 1.0) the existing contractually available supply flows are not sufficient and the whole gas distribution system, except its south-east and northern areas, could be insufficient – see Fig. 6. Note that by applying the design factor of 0.45 we managed to get rid of all the low-pressure areas. However, assuming firm customers at 45% of January load in the Fall is unrealistically low.

Fig 6. 2028 Fall Loading Case Pressure Distribution Map with Design Factor 1.0

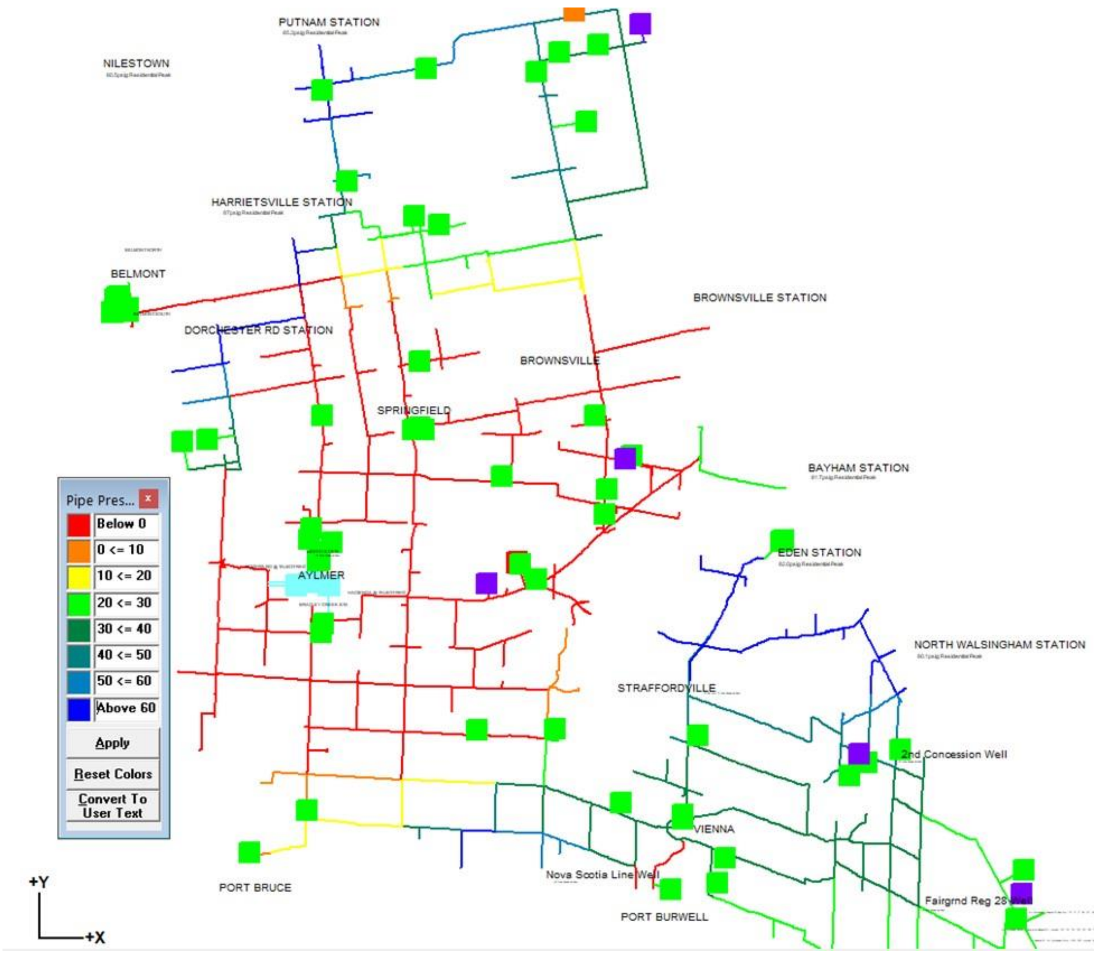


Table 2. 2028 Integrity Studies, Calibration Details and Flow Balances

	Calibration targets, EPCOR data		January 2028 case without 9608 Carter Rd		January 2028 case, all loads are on		Fall 2028 case, break-even, all loads are on		Contractual limits
	Flow, m^3/h	Pressure, PSI	Flow, m^3/h	Pressure, PSI	Flow, m^3/h	Pressure, PSI	Flow, m^3/h	Pressure, PSI	Flow, m3/h
BROWNSVILLE	84.5	35	32.8	35	110.2	35	207.2	35	113
HARRIETSVILLE	2394.8	78.4	2400	80	2400	80	2400	80	2408
N WALSINGHAM	1098.8	77.9	977.2	77.9	1001.8	77.9	957.9	77.9	1170
EDEN	563.5	71.78	841.5	71.8	871.9	71.8	839.9	71.8	703
PUTNAM	2225.8	76.5	2300	80	2300	80	2300	80	2342
BAYHAM	957.9	79.6	1800	80	1800	80	1800	80	1854
DORCHESTER	1436.9	82.9	1700	80	1700	80	1700	80	1706
2ND CONCESSION WELL	40	72.4	40	56.2	40	54.9	40	56.8	40
FAIRGROUNDS WELL	100	70.6	100	49.8	100	47.8	100	50.2	100
NOVA SCOTIA WELL	100	58.1	100	63.5	100	61.2	100	62.4	100
LAKEVIEW	2479.3	76.5	2768.7	76.5	3041.1	76.5	2864.4	76.5	2685
Total flow-in (supply)	**11,481.50**		**13,060.20**		**13,465.00**		**13,309.40**		**13,221.00**
Total flow-out (demand)	N/A		12049		13179		13224		N/A
Supply surplus as % to the demand			8.4		2.2		0.6		

The distribution system capacity is insufficient in the central region and will require reinforcement. Refer to section 7.2. for greater details.

Table 2 indicates station capacities in red where they exceed current supply capacity contracts with gas wholesale providers (Enbridge and others). Note that the contractual limits (green figures in the right column) are not a physical restriction of the flow. As long as the distribution system with the given demands is able to pull the gas from these supply points, actual flows are balanced out by the loads and the system's given conditions. Thus, actual flows can surpass those contractual limits. Essentially, the table's red figures are an indication of possible future negotiations necessity with the corresponding wholesale gas suppliers.

Per ENGLP request Cornerstone ran additional simulations to clarify some details associated with three prospective customers: Large Agricultural Customer, Cogen facility at Carter Rd 9608 and Aylmer Industrial Park (their locations identified on Fig 4 by short arrows).

The new large agricultural customer (black arrow on Fig 4) requested significant demand increase over initially planned peak of 161.6 m3/h. Cornerstone simulated possible increase of demand without changing of the 2028 model setting. These simulations revealed that it would be possible to provide 2-3 times rise of the flow but only along with corresponding increase of the contractual flow limits. Table 3 summarizes selected scenarios comparable to those in Table 2. Stations' capacities exceeding contractual limits are also shown in red.

Table 3. Maximum Available flow and Corresponding System's Flow Balances as Simulated by the 2028 Integrity Studies Model

	January 2028, 9608 Carter Rd OFF		January 2028 case, all loads are ON including 9608 Carter Rd				Fall 2028 case, 75% demands, 4" to EZ Grow with 510 m3/h flow		Contractual limits
	2" to EZ Grow, 308 m^3/h flow		2" to EZ Grow, 297 m^3/h flow		4" to EZ Grow, 525 m3/h flow				
	Flow, m^3/h	Pressure, PSI	Flow, m^3/h	Pressure, PSI	Flow, m^3/h	Pressure, PSI	Flow, m^3/h	Pressure, PSI	Flow, m3/h
BROWNSVILLE	27.7	35	106.8	35	108	35	209.2	35	113
HARRIETSVILLE	2400	80	2400	80	2400	80	2400	80	2408
N WALSINGHAM	1014	77.9	1032.5	77.9	1119.1	77.9	1100	77.9	1170
EDEN	866	71.8	892.5	71.8	961.4	71.8	953.9	71.8	703
PUTNAM	2300	80	2300	80	2300	80	2300	80	2342
BAYHAM	1800	80	1800	80	1800	80	1800	80	1854
DORCHESTER	1700	80	1700	80	1700	80	1700	80	1706
2ND CONCESSION WELL	40	54.9	40	54.9	40	54.9	40	53.2	40
FAIRGROUNDS WELL	100	47.8	100	47.8	100	47.8	100	44.5	100
NOVA SCOTIA WELL	100	61.2	100	61.2	100	61.2	100	61.5	100
LAKEVIEW	2918.6	76.5	3184.4	76.5	3234.8	76.5	2962.6	76.5	2685
Total flow-in (supply)	**13,266.3**		**13,656.2**		**13,863.3**		**13,665.7**		**13,221.0**
Total flow-out (demand)	12195		13315		13543		13224		N/A
Supply surplus as % to the demand	8.8		2.6		2.4		3.3		

Table 3 results could be further improved if the settings of 3 relevant stations (Lakeview, North Walsingham, and Eden) were changed. Such optimization of the settings, supply capacities and possible piping modification requires a dedicated study. Nevertheless, the potential impact of increased flow/load to the new large agricultural customer on the remaining system is in scope and therefore briefly summarized as follows.

There is no significant impact on the pressure distribution with increased flow to the new customer providing there is additional supply at Lakeview and Eden stations. Basically, despite the flow increase, the pressure distribution map would be very similar to what is shown on Fig 3. In case if proposed power generation facility at 9608 Carter Road is off (gray arrow on Fig 4 indicates the location) the pressure distribution would be slightly worse than shown on Fig 4 but still similar (some bright green piping segments would turn into yellow). However, such worsening is not critical as it can be easily compensated by pressure rebalancing of those 3 relevant stations directing Lakeview station's flow back to central Aylmer district. In general, the south-east part of the gas distribution system (where the customer is located) could be "isolated" from the remaining system. That isolation/separation could be accomplished through correct pressure setting balance of those 3 abovementioned supply stations. Correct pressure balance will keep the impact of this increased flow contained within that south-east district with no tangible influence on the remaining system. The setting balance of the 2028 model turned out to be sufficient to minimize the impact for fall load case. The 75% system load case (comparable to the fall break- even one listed in Table 2) demonstrated pressure distribution very similar to what is shown on Fig 5.

Aylmer Industrial Park (red arrow on Fig 4 indicates the location) was examined to determine the capacity of the existing 2" pipe along White Street connecting prospective park with Elm Street existing 4" pipeline.

Cornerstone simulations revealed that the existing 2" connecting pipe can deliver maximum flow of approximately 400 m^3/h with best available pressure distribution. Therefore, its capacity is not sufficient to support Aylmer Industrial Park's targeted 708 m^3/h. Moreover, that best pressure would be available only in case the prospective power generation facility at 9608 Carter Road is switched off. In this case a 4" connecting pipe would be sufficient to support more than that 708 m^3/h target (as shown on Fig 4). However, as was shown on Fig 3, when 9608 Carter Rd power generation is operational, the whole northern part of the central Aylmer district runs out of gas. That means, no matter what size that connecting pipe would be - the gas supply to the park would be impossible through the current Elm Street pipeline. That in turn means, the issue regarding the correct size of that connecting pipe is not a stand-alone one but should be resolved in framework of central Aylmer district pressure distribution improvement.

A similar situation was observed for the connection pipe to prospective power generation facility at 9608 Carter Road. There is currently a 4" pipe connecting Carter Road customers to the existing Talbot Road main. And gas pressure in this main around the tap-in location could be less than 10 psi when the proposed power generation facility is operational (refer to Fig 3). Nearby RNG supply with contractual supply capacity of 24 GJ/h (~ 620 m^3/h) could alleviate that pressure deficiency, but it cannot support targeted demand of 1130.0 m^3/h when there is no gas supplied from the distribution system. Simulations suggest that required 1130.0 m^3/h flow through such 4" connection pipe needs at least 13 psi pressure at the intake. Thus, this is also not a stand-alone issue as it should be resolved in framework of central Aylmer district pressure distribution improvement.

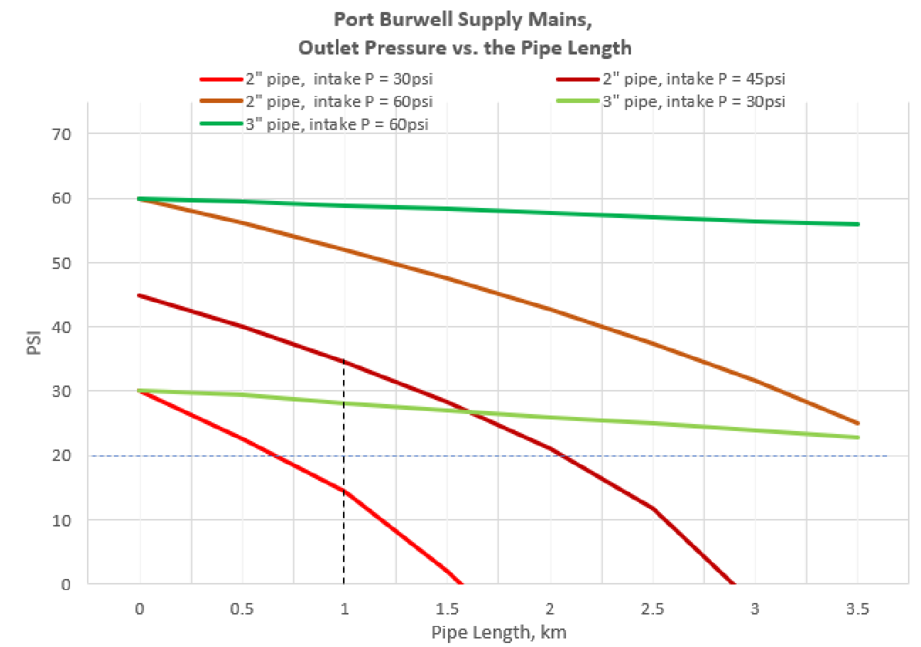
7 PROPOSED CAPITAL PROJECTS

7.1 POSSIBLE PIPING UPGRADE TO ADDRESS THE 2023 POTENTIAL ISSUES

7.1.1 BURWELL AREA IMPROVEMENT PROJECT

Port Burwell is fed by two independent 2" mains, one feeding each side of Big Otter Creek. The system model typically does not include mains downstream of district regulators, but these two mains are downstream and operate at 30 PSIG and are included in the model. When the peak town loads are modeled as aggregate loads located at the southernmost point of each town subsystem (east and west sides) inadequate pressure results. The most cost-effective solution would be to raise the operating pressure of both systems, rather than replacing the 2" mains with larger pipes. Fig 6 shows the impact of pressure increases and pipe replacements.

Fig 6. Flow Analysis Summary of Port Burwell mains



7.1.2 BELMONT AREA IMPROVEMENT PROJECT

Southern Belmont area may need an improvement project to improve piping capacity. Belmont is currently supplied by two mains/streams – the northern part of the town is fed by the Nilestown station while the southern Belmont receives gas from both the Harrietsville and Dorchester stations. Each stream goes through a district regulation station set to 30 PSIG. However, those regulating stations do not have metering capacity. Thus, it is impossible to know how much help may be received by the northern and the southern areas from each other to meet the whole town's demand. This flow split must be estimated during modeling. As mentioned earlier, simulation of the northern Belmont stream revealed healthy supply which should be capable of delivering at least 50% more flow compared to the 2023 level with no system pressure issues anticipated. At the same time simulation of the southern stream suggests possible problems with the system pressure with the existing 3" pipe from the intersection of Yorke Line and Elgin Road toward Belmont South station. This piping segment comprises two sections

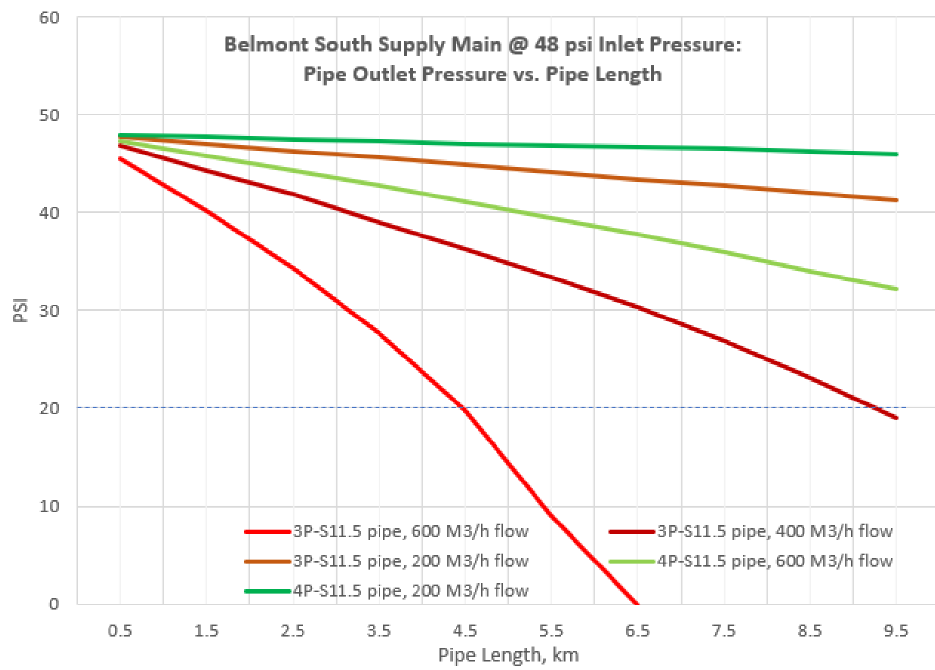
– the one close to Belmont is approximately 3.7 km of hydraulic length and the other one is ~3.9 km. The pressure at that intersection was calculated at 48 psi.

That possible southern stream's problem was determined based on simulated flow which cannot be verified because no field data is available. If the actual flow into the southern area of Belmont is less than assumed in the model, then the problem may not materialize therefore no capital improvement project would be required for this piping.

Since no metering data available we decided to run an additional simulation of that problematic pipe segment with possible lower flow. The goal was to understand if the existing pipe could deliver the required pressure in case of less flow. This additional simulation is performed by GasCalc software, same way as we did it for the Port Burwell area. Refer to Fig 7 for details.

Fig 7. Illustrates the level of sensitivity of the resulting pressure at Bellmont South to the assumed flow into that district regulator and shows the impact of a pipe replacement in the 8km section feeding Belmont South.

Fig 7. Flow Analysis Summary of the Belmont South Main



We recommend installation of permanent or temporary metering at district regulation stations and collecting statistical data regarding actual flow through that piping segment. This data would be used to calibrate the system model and improve the accuracy of the predictions.

7.2 SUPPLY CAPACITY UPGRADE PROJECTS TO ADDRESS THE 2028 DEMANDS

Cornerstone performed several simulations trying to increase the piping size along with the capacity additions to the existing stations in the area surrounding the proposed power generation facility at 9608 Carter Road.

Based on simulations of numerous options including possible supply capacity upgrade also at Eden and Harrietsville stations we concluded that only the two following options would be most realistic. All remaining simulated cases had obvious disadvantages compared with these two potential projects (usually a significantly longer piping upgrade and/or difficulties to apply for additional for contractual supply volumes).

7.2.1 PIPING UPGRADE NEAR BAYHAM STATION

Bayham supply station is the closest one to the critical proposed customer at 9608 Carter Road, thus a project to improve the system efficiency and capacity of this area by a larger pipe was an obvious idea. The goal also was to identify the minimum required length of such upgraded pipe segment. After a few iterations Cornerstone substantiated that minimum required length at approximately 5.5 km – the existing 4” piping should be upgraded to the size 6” from Bayham station to the intersection of Talbot Line and Somers Road. See yellow highlighted pipe on Fig 8 showing pressure distribution map for that case.

It is also possible to achieve above 20 psi pressure throughout the entire Aylmer surrounding area as shown on Fig 9. It requires piping upgrade to size 6” up to Carter Road without changing existing contractual supply limits. Alternatively, it is possible to shorten the piping upgrade - from Bayham to the intersection of Talbot and Heritage Lines but with up to 30% supply limit increase at Bayham to 2300 m3/h. See yellow highlight on Fig 9, this is approximately 13.5 km. Thus, there should be thorough business cases comparison to conclude if achievement of 20 psi pressure at Aylmer worth the investment of additional 8 km of the piping upgrade.

Note that only January 2028 loading cases are illustrated in this section. Cornerstone also ran Fall load case for the 5.5 km upgrade. The pressure distribution was slightly better compared to January 2028 (see Fig 8.) because the towns were at 77% and therefore less flow required through those critical pipes. 77% is the break-even point to balance out the demands and the contractually available capacities when the seasonal customers are on in a fall season.

Fig 8. January 2028 Pressure Distribution Map with Upgraded Piping Segment Near Bayham Station

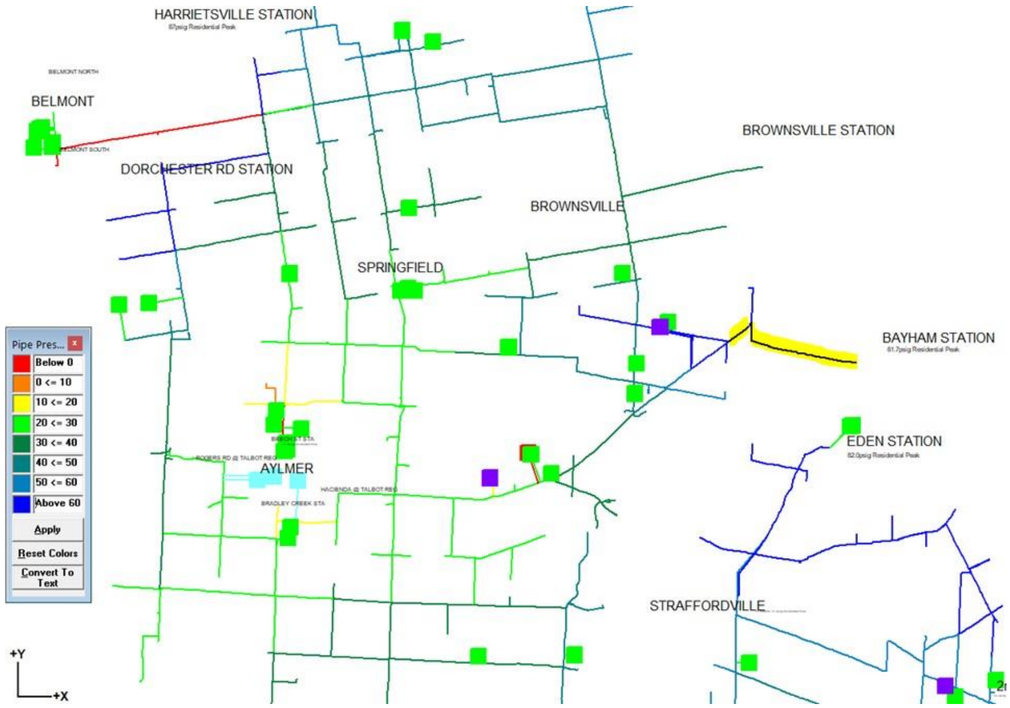
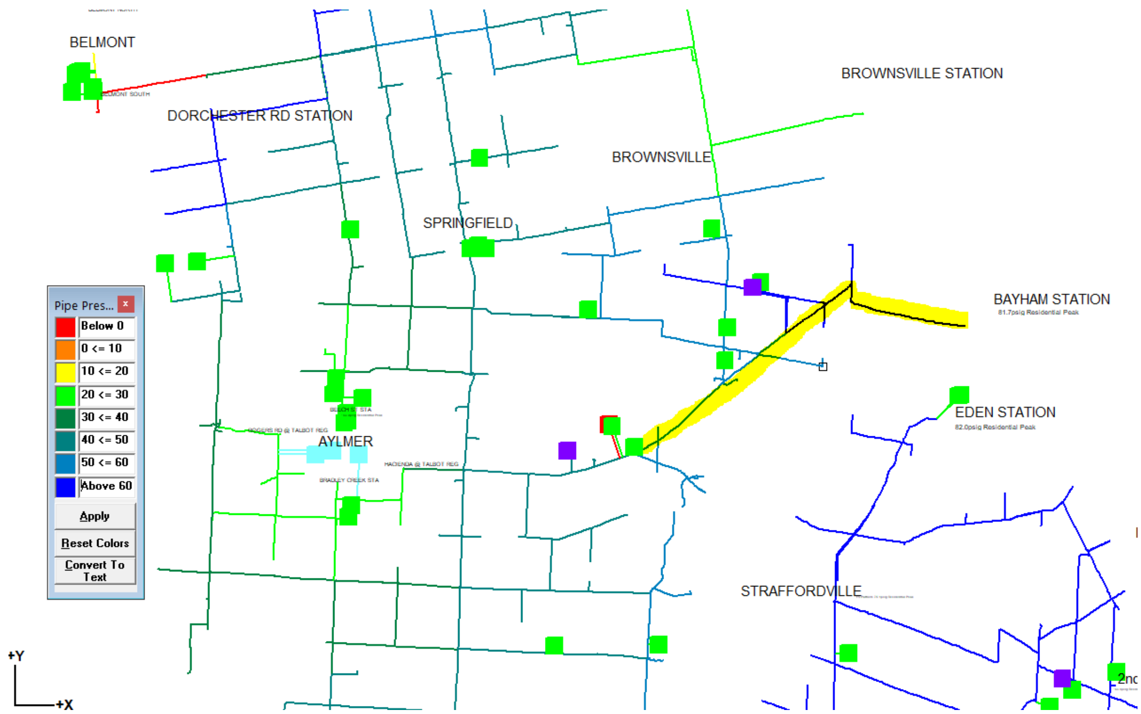


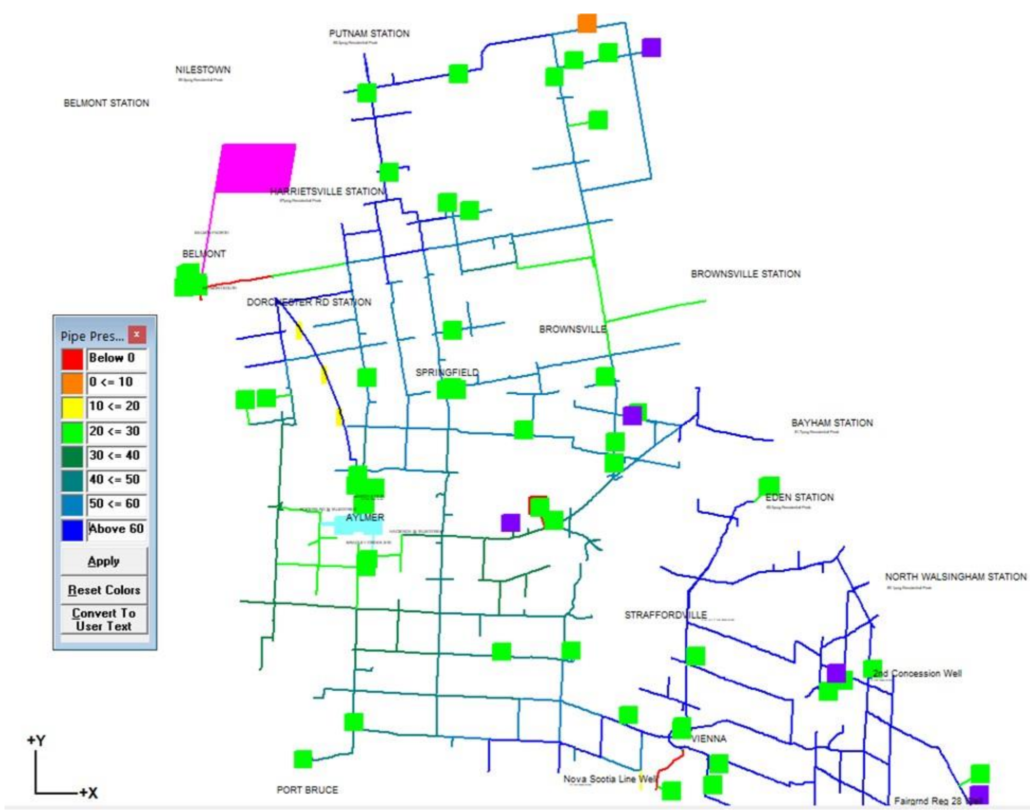
Fig 9. Pressure Distribution Map with Longer than Fig 8 Piping Segment Upgraded to 6”



7.2.2 DEDICATED 6” PIPELINE FROM DORCHESTER TO THE PROPOSED AYLMER INDUSTRIAL PARK

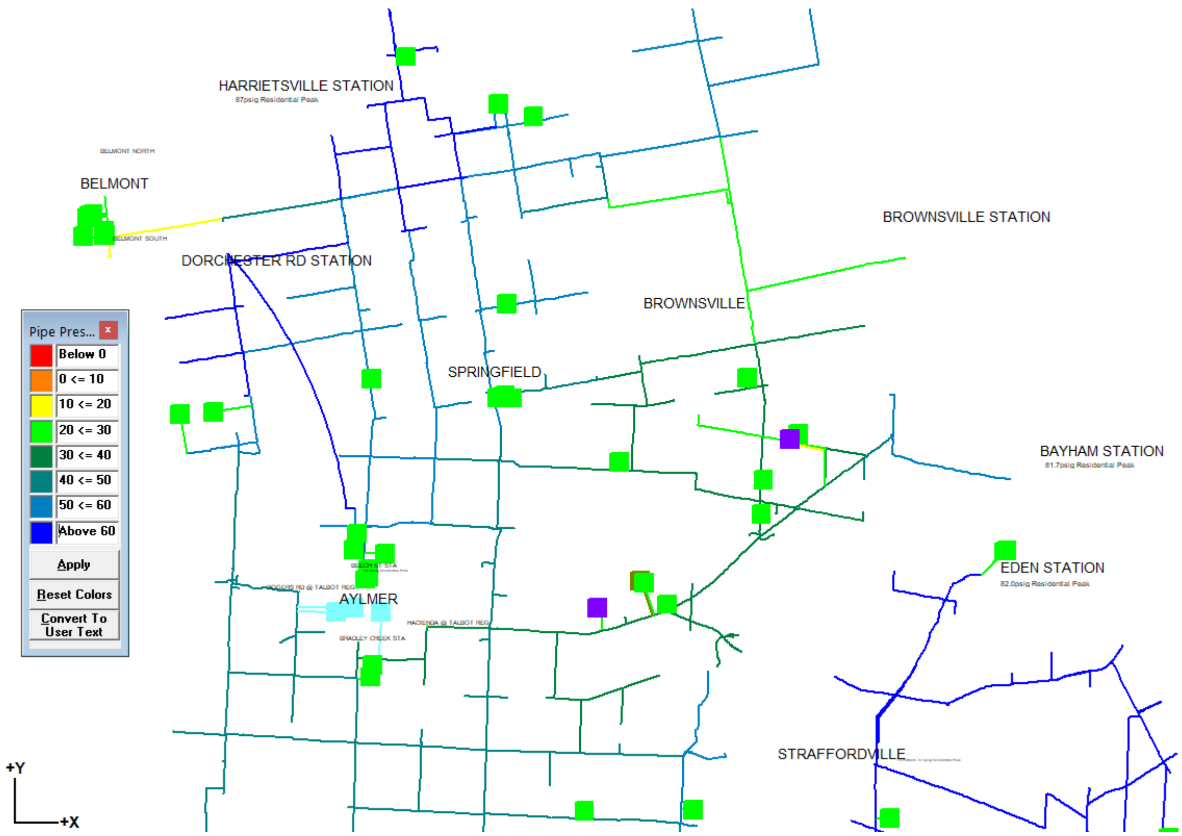
Cornerstone performed several iterations to find out a realistic and effective way to deliver required supply volume from the Dorchester and Lakeview stations to the proposed AIM. Preliminary simulations revealed that a simple shortcut through extension of either Glencolin or College Lines piping does not work as it changes the pressure distribution balance instead of increasing the whole system’s pressure. Partial upgrade to larger size of some piping from Lakeview station results in a similar pressure distribution skew instead of desired increase in the whole area. Moreover, the total length of the Lakeview bound piping of approximately 20 km is obviously not feasible. Those preliminary iterations helped Cornerstone to came to conclusion that a dedicated pipeline (a brand new main) from Dorchester station to proposed AIM delivers desired pressure increase in the whole Aylmer district and provides additional passage to the Carter Road proposed customer. We estimated the new main length at approximately 10 km, which is less than the Bayham piping upgrade allowing to achieve same pressure distribution evenness. And that new pipeline from Dorchester makes Bayham piping upgrade unnecessary. See Fig. 10 for more details.

Fig 10. New Dedicated 6" Pipeline from Dorchester Station to Proposed AIM, January 2028



The simulations also indicated that a 4" size could marginally support the January loads instead of the more expensive a 6" one. However, fall load case simulations discovered that a 4" would not meet the 20+ psi target in this case. Fig 11 shows pressure distribution map for 2028 fall break-even load case. The design factor at the break-even point is 78% (the interruptible customers are consuming their full load while the firm customers' total load is at 78%). The flow-in (supply) is equal to the existing total contractual limits of 13221 m^3/h with the total flow-out (demands) perfectly balanced out in the model with less than 0.1% difference. If the firm customers' total load would be steady above 78% then application to increase the existing contractual supply limits may be necessary.

Fig 11. New Dedicated 6" Pipeline from Dorchester Station to Proposed AIM – Fall Break-even Loading Case

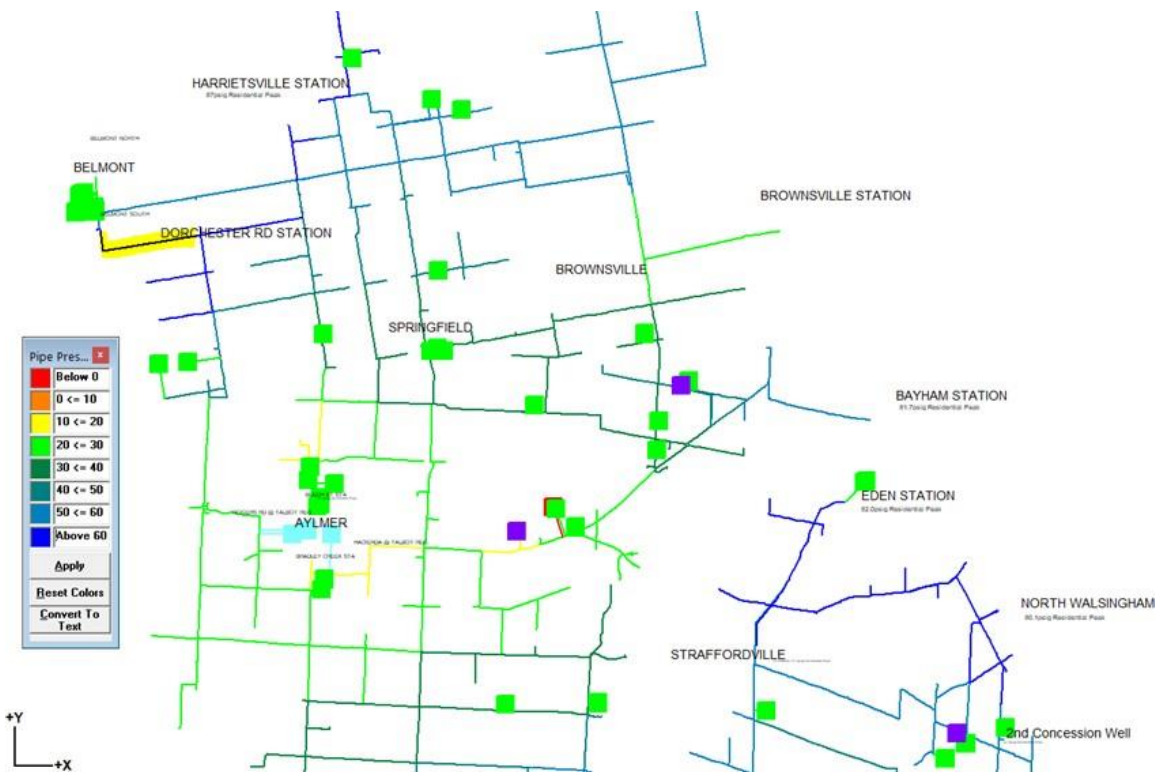


7.2.3 NEW PIPELINE ALONG WILSON RD TO RESOLVE BELMONT CONSTRAINT

ENGLP suggested evaluating an option to resolve the Belmont area problem (refer to section 7.1.2.) with new piping on Wilson Road also hoping it should alleviate the congestion at central Aylmer district.

Simulation results suggest that a new 4" line (as highlighted on Fig 12) is not only resolving the Belmont area problems but also improves pressure distribution at Aylmer and eastern central districts (near Carter Road) for winter loads. Fig 12 shows simulation detail with proposed power generation facility at 9608 Carter Road area active. As we can see, the marginal pressure in a few piping segments should be still above 10 psi. Note that this pressure distribution is expected without any additional piping or capacity upgrade at Bayham station.

Fig 12. New 4" Pipeline on Wilson Road, January 2028 loading case

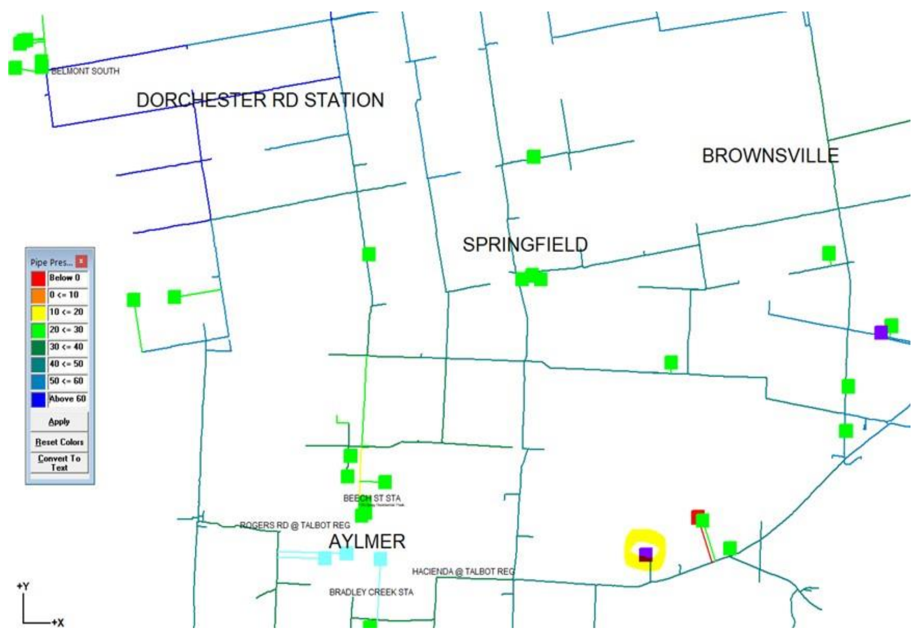


Moreover, if that proposed power generation facility at 9608 Carter Road area (circled in yellow on Fig 13) would not be constructed then that additional line at

Wilson Road would help significantly to alleviate the marginal pressure issue at central Aylmer. Refer to Fig 13 for greater details.

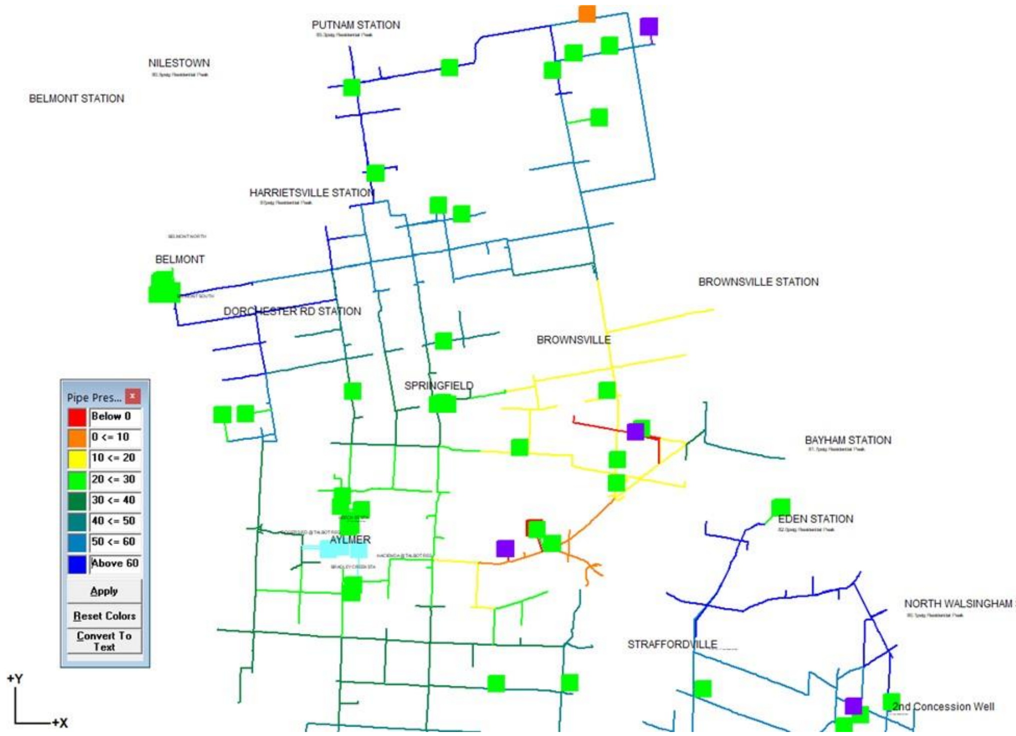
However, simulation of the fall loading case revealed that even for the supply to demand break-even balance the map distribution would be improved only at Belmont but not at eastern Aylmer toward Bayham/Brownsville.

Fig 13. New 4" Pipeline on Wilson Road, January 2028 loading case without 9608 Carter Road proposed client



The main reason for worse than winter pressure distribution is the large proposed seasonal customer (Lofthouse Grain Dryer at 54681 Best Line) with significant load of 1359.4 m3/h. Refer to Fig 14 for break-even pressure distribution map.

Fig 14. New 4" Pipeline on Wilson Road, Break-even Fall 2028 loading case (the 9608 Carter Road proposed client is on)



Essentially, while the addition of a new pipe along the Wilson Road resolves the congestion at Belmont area and helps to alleviate pressure distribution at Aylmer district in wintertime it is not able to provide sufficient gas supply to the above-mentioned large seasonal customer and related districts east of Aylmer. That means, the addition of pipeline at Wilson Road is not an alternative but rather a supplement to the capital projects discussed in the sections 7.2.1 and 7.2.2.

7.3 PROPOSED CAPITAL PROJECTS TO ADD A NEW SUPPLY STATION

An idea to add a brand-new supply station close to the proposed 9608 Carter Road customer was discussed with ENGLP. Preliminary simulations of such station addition at notional location around the intersection of Talbot and Springfield were performed. The simulation results were promising – it is possible to achieve similar to Fig 9 and 10 pressure distribution without upgrading the existing piping. However, the idea of a brand-new additional supply station is currently not in practical scope as possible connection to a major (Enbridge) pipeline is yet to be determined. Thus, it cannot be considered as a realistic alternative to discussed in previous sections projects as no relevant details are available at this point.

EPCOR

Stone Olafson

Cost of Service, Ontario

Prepared for EPCOR – May 2024

Table of Contents

Stone Olafson

Research Overview

Why we are doing the research

As demand for natural gas continues to increase, EPCOR's investment in infrastructure development, maintenance, and data privacy increases with it. With this in mind, a new approach to EPCOR's cost of service is being considered.

This research was conducted to identify satisfaction of customers in Aylmer Ontario, and neighboring communities, how they are currently being serviced, their willingness to invest more for increased operational demand, and their appetite for alternative energy sources in the future.

Objectives:

- Understand the level of satisfaction with EPCOR services.
- Determine natural gas use and appetite for alternative heating source methods.
- Identify customer willingness to invest more for increased service and operational maintenance.

Who we spoke with

An online survey was distributed to current EPCOR customers located in Aylmer Ontario and neighboring communities. This was achieved using their internal customer database.

Responses were collected between May 9 – 23, 2024

A sample of n=307 completed responses was collected, providing a margin of error of ±5.5%, 19 times out of 20.

EPCOR

The Story On One Page

1

Satisfaction with EPCOR is high despite perceptions of high energy costs.

Customers remain very satisfied with EPCOR's natural gas services and although affordability is of top concern, EPCOR continues to keep customers happy with their commitment to planning and maintaining service.

This leads to positive experiences and overall trust for the brand.

2

As costs rise, so too will customer expectations, making reliable service imperative.

Community members are concerned with their utility costs and most feel their monthly bills are higher than they were last year.

With this in mind, additional price increases will cause hesitancy along with an increase in customer expectations, making accountability and reliable service even more important.

3

Consideration of alternative heating solutions is not currently a priority.

EPCOR customers are satisfied with their current level of service and do not feel the need to change what seems to be working for them.

Customers may have become complacent with their heating solutions and therefore not a topic often discussed within most households.

However, those who are new to their community tend to have these conversations more often than those who have lived there longer.

4

Although nominal increases to utility costs are largely unsupported, Data privacy is noteworthy.

Any nominal increase to utility bills causes hesitancy among customers as affordable service remains top of mind.

Increased costs to mitigate service interruptions and renewed infrastructure are supported less, while investment in managing data privacy has more support.

Key Highlights

Key Highlights

Satisfaction for EPCOR as a natural gas service provider is high, and customers understand the importance of continued planning and maintenance.

Although utility costs are a concern for many customers, overall satisfaction for EPCOR remains high with 67% saying they are satisfied with EPCOR as their natural gas service provider.

The value of EPCOR is also very apparent as customers see the importance of planning and maintenance, particularly when it comes to infrastructure improvements to improve reliability and safety, as well as accessibility through customer service and support.

This level of satisfaction is a key factor in maintaining trust and loyalty to EPCOR despite rising utility prices as industry demand and operational costs continue to increase.

Affordability, reliability, and accountability are expectations.

The top concern for customers right now is affordability, with 87% saying this is the top priority when considering community investment in natural gas. As a result, most customers feel their monthly utility bills seem higher than they did a year ago. However, age does seem to be a factor as those who are a part of an older generation tend to feel that current rates have remained fair.

Beyond the overall costs to community members, reliability is also rated a high priority with 70% of customers claiming this to be their top consideration for additional community investment. As prices increase, customers want to know this cost will also increase the overall value. This will also lead to higher expectations from community members.

Key Highlights

People are happy with their current service, leaving alternative energy solutions unexplored.

64% of EPCOR customers want a moderate level of investment to ensure their current service level is maintained, and 14% believe higher investment is necessary.

Customers are satisfied with their current level of service and have yet to see the value of how additional investments may be beneficial. This could cause a level of complacency as customers are happy with the status quo. Customers feel confident in EPCOR's current service and reliability and do not feel the need to consider making any significant changes to their heating solutions at this point.

However, 20% of the market does have alternative energy sources, like electricity, top of mind within their household, with many considering making a change within the next 3 years. These customers are most often new to the community and tend to be male.

Data management and security investment has some support.

Customers remain hesitant to support any investment that may increase their monthly payment, even in nominal amounts. Managing service interruptions and maintaining the natural gas infrastructure may be seen as expectations rather than added value to them personally, making additional service charges less understood.

Data management and privacy, however, have slightly more support, particularly from older demographics. This is likely due to the personal relationship customers have with their data and want to ensure their information is secure and not susceptible to compromise.

As investments to infrastructure, data, and service interruptions increase it may become important to ensure community members are knowledgeable about how these additional charges may benefit them individually. Information about how these additional costs will be of value to them in both the short and long term could help increase their support.

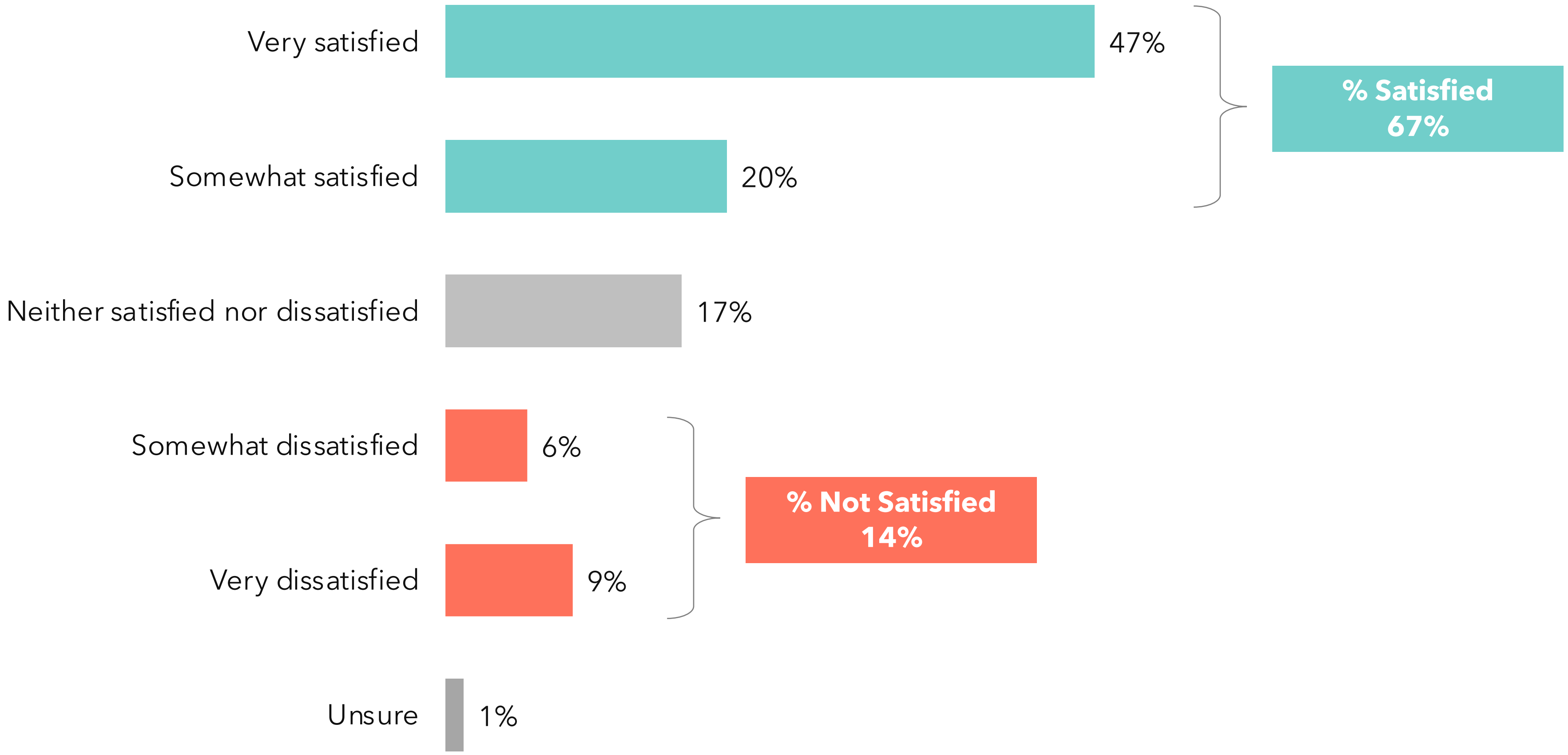
Detailed Findings

Satisfaction, attitudes, and service

EPCOR continues to retain a high level of customer Satisfaction.

Stone Olafson

EPCOR has a strong level of overall satisfaction with two-thirds of customers feeling satisfied with their natural gas service.

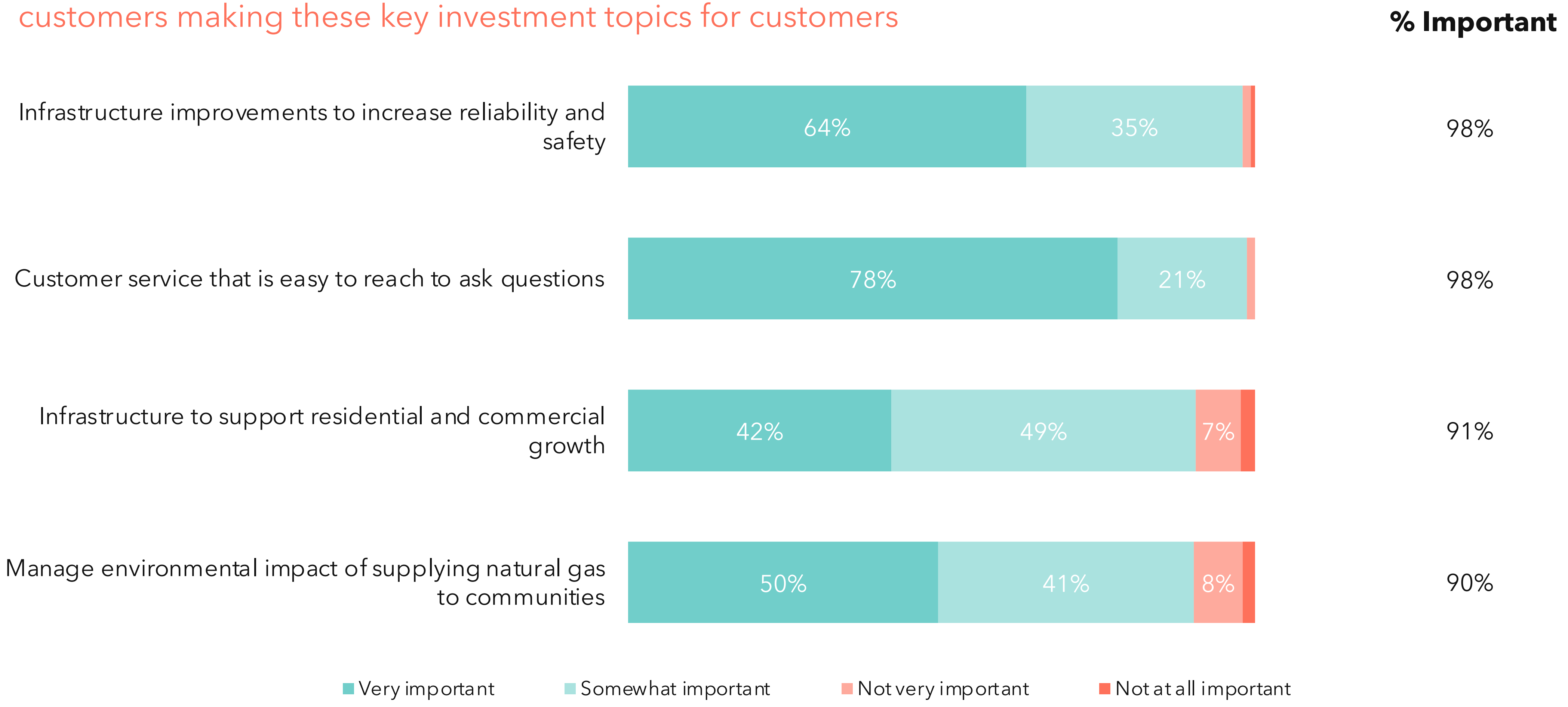


EPCOR

Base: All respondents (n=307)
Q5. How would you rate your OVERALL satisfaction with EPCOR as your community's natural gas services provider?

Improvements to infrastructure and customer service are most important.

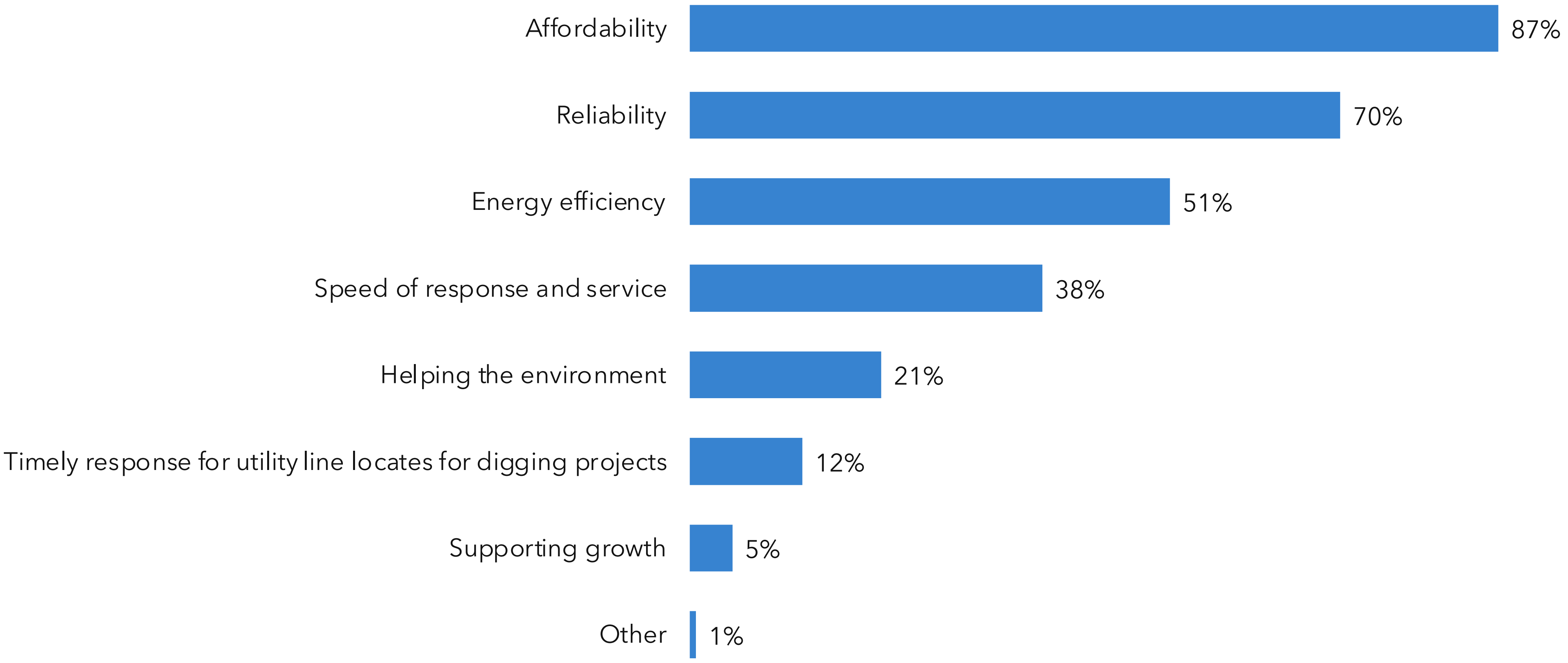
While all planning and maintenance services are highly important, infrastructure improvements as it relates to safety, and customer service are important to all EPCOR customers making these key investment topics for customers



Base: All respondents (n=307)
Q6. As the local natural gas distribution provider, EPCOR conducts service planning and maintenance based on community growth, changes in demand, changes in climate, and renewing/protecting aging infrastructure. Rank the following options based on their importance from "Not at all important" to "Very important".

While affordability is the top priority overall, reliability is a significant factor for community investment.

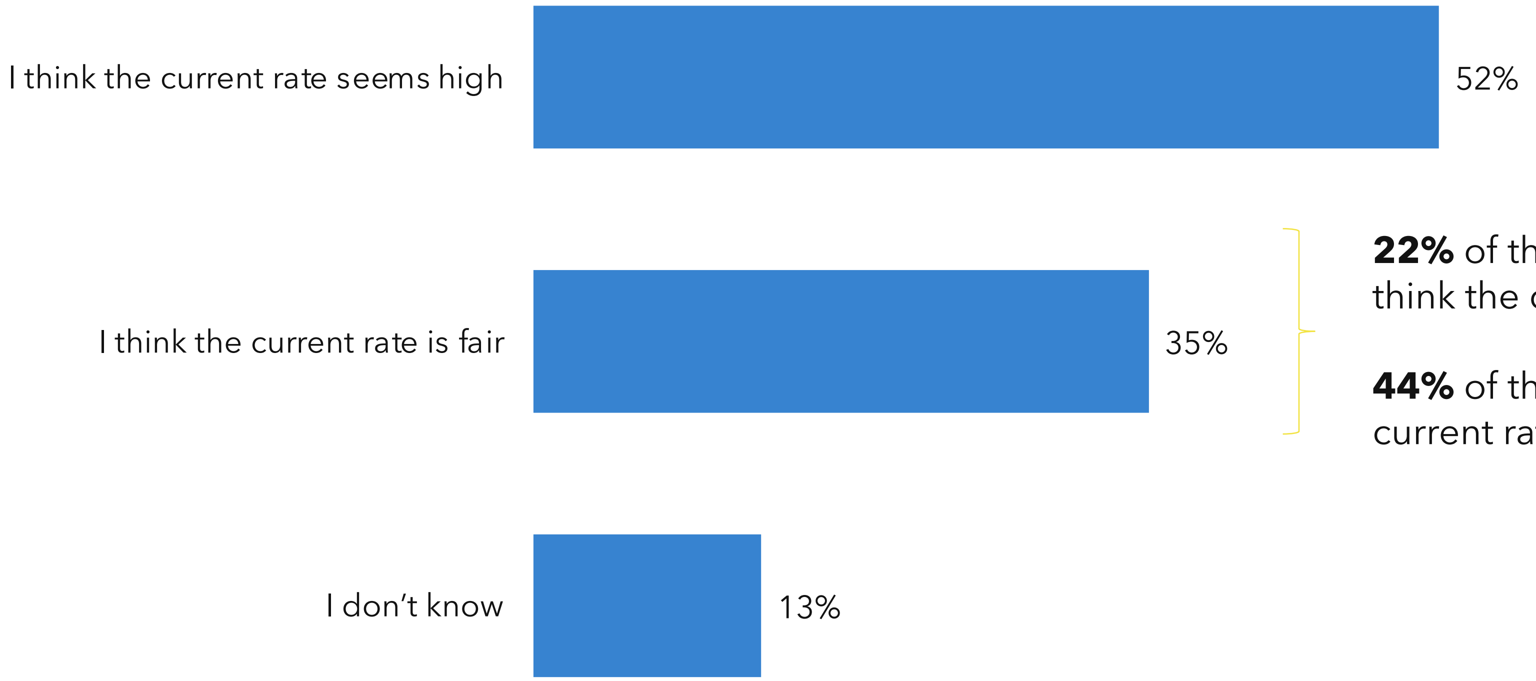
Customers are most concerned with affordability with the vast majority agreeing that this is their top priority. While costs are always a priority for customers, the importance of reliable service (70%) and energy efficiency (51%) are highly important.



Base: All respondents (n=307)
Q7. What are your top priorities when considering community investments in natural gas?

The majority of customers agree that rates seem high compared to last year, but age is a factor.

While over half of EPCOR customers believe the current rates to be higher than last year, 1/3 believe their monthly payments seem fair. Due to perceptions, there is likely to be hesitancy toward nominal increases to their utility bill.



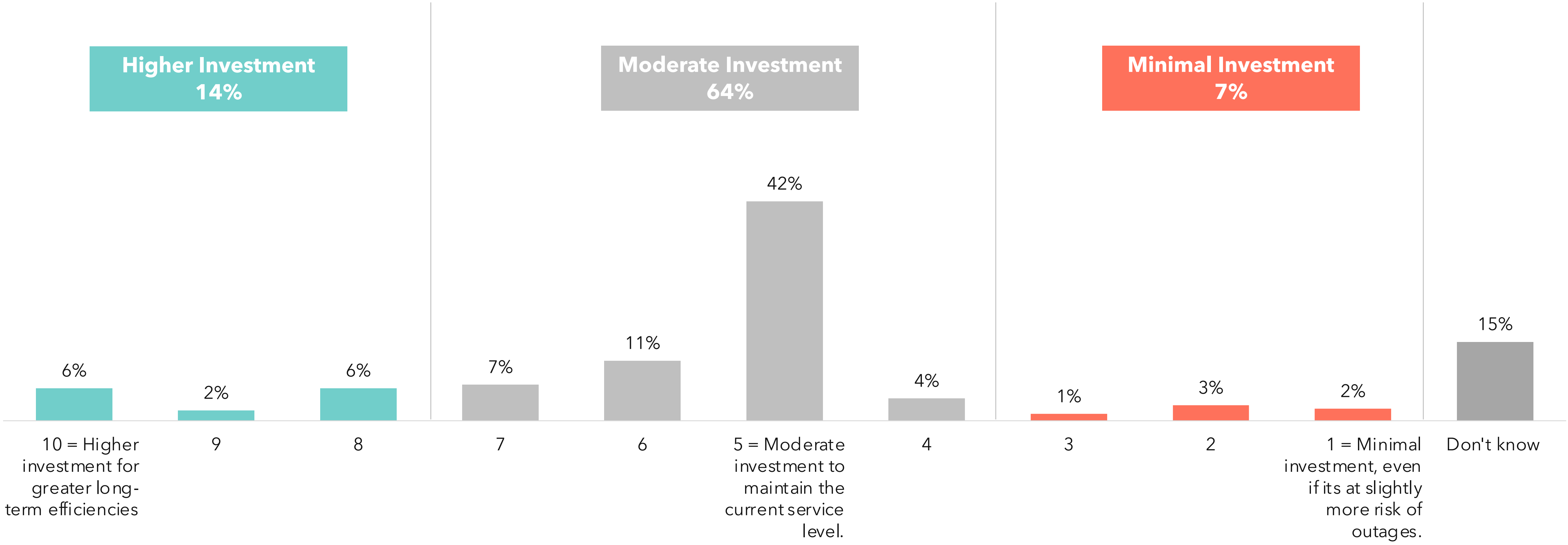
22% of those between 35 – 54 think the current rate is fair

44% of those 55+ think the current rate is fair

Base: All respondents (n=307)
Q11. Monthly rates for safe and reliable natural gas services in your community are regulated through the Ontario Energy Board. How do you feel about the rate you pay for these services today compared to what you were paying last year?

Customers are satisfied with their current level of service and investment.

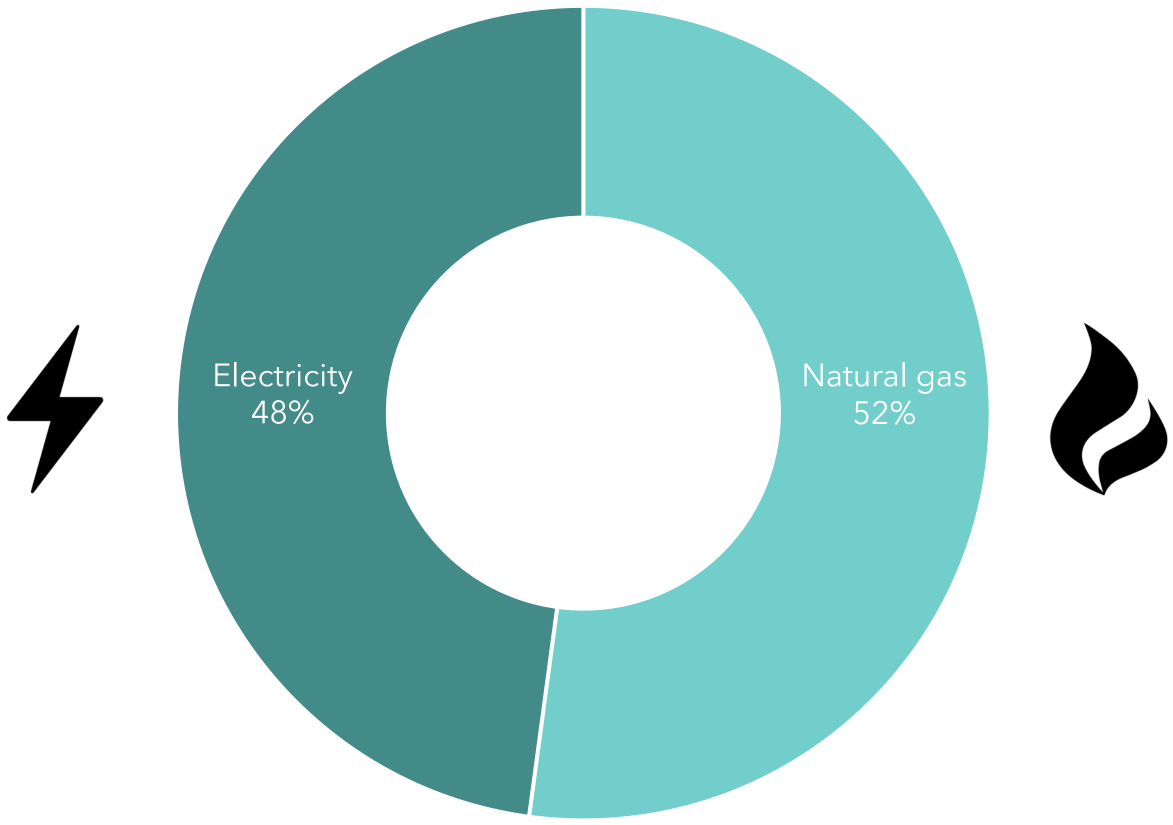
With a high level of satisfaction, and affordability the top priority, it is not surprising that most customers are happy to maintain the status quo. Although 14% are interested in an increase in investment, the majority simply want their service levels to be maintained with moderate investment in the future.



Base: All respondents (n=307)
Q12. Natural gas service requires ongoing maintenance for homes and businesses to ensure safety and reliability. Looking ahead to the next several years, how important is ongoing investment on a scale of 1 to 10 where:

Natural gas is most common for households, but electrically powered appliances are very apparent.

Household appliances are almost evenly split between electric power and gas power, with slightly more household items using natural gas. Fuels like propane and oil are not used at all.

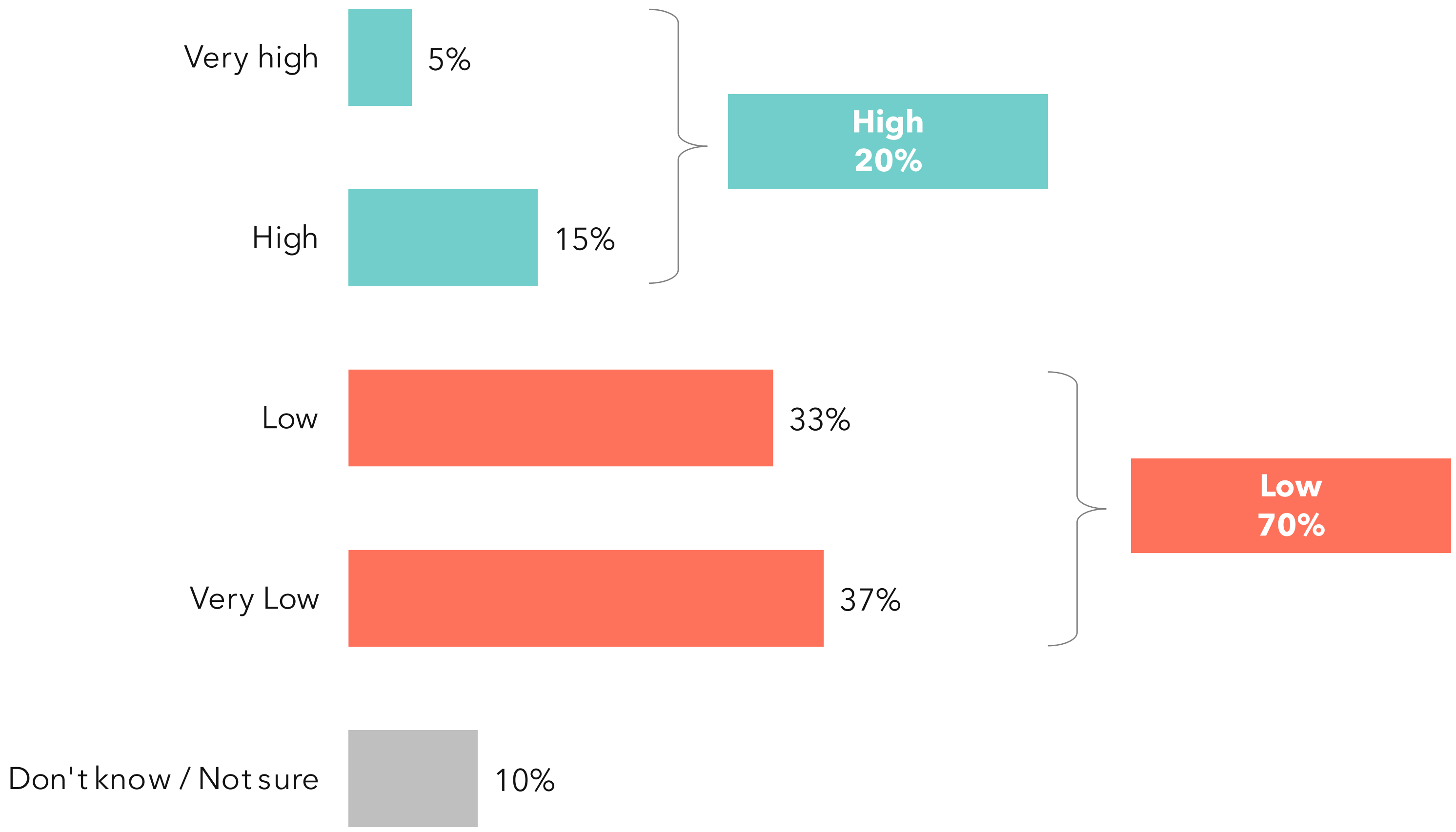


Base: All respondents (n=307)
Q14. Now, thinking about the energy in your home, which of the following is the PRIMARY source of energy for your home appliances?

A transition to electric energy sources is a priority for 20% of the market.

Stone Olafson

While a transition to electric utilities is not a point of consideration for most, it is a high priority topic for one fifth of the market. Energy transition tends to be a higher priority for those newer to the community they live in.

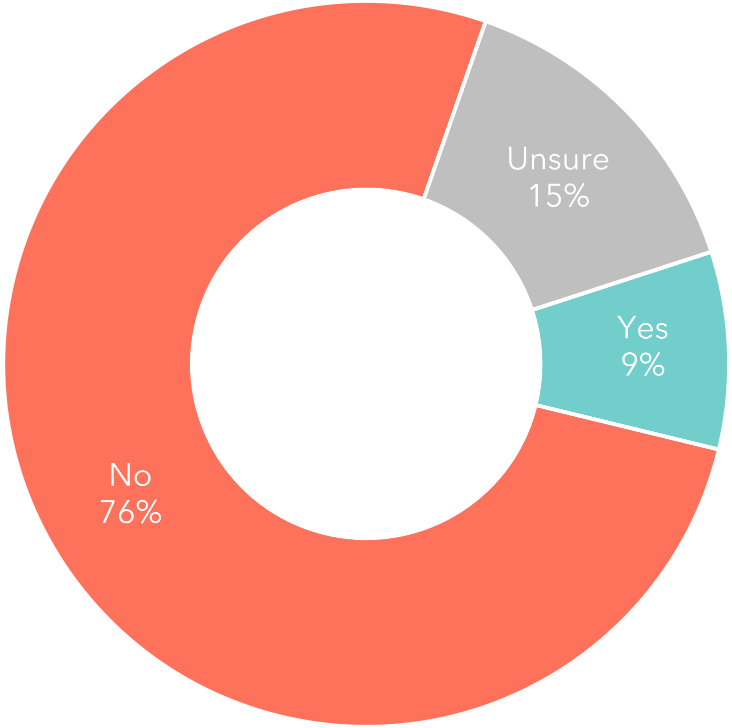


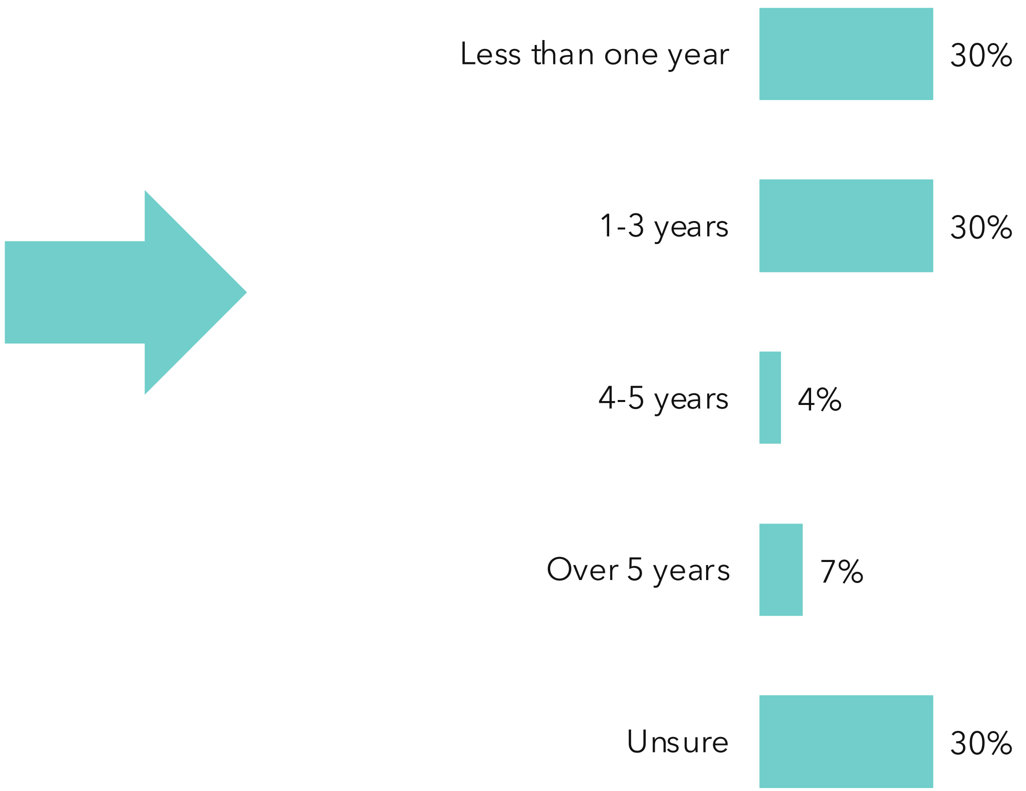
Base: All respondents (n=307)
Q13. Energy transition refers to the growth of electrically powered devices and utilities like electric vehicles vs gas powered vehicles and electric air source heat pumps vs gas-fired furnaces. How much of a priority is the topic of energy transition in your household?

EPCOR

Considering a change to alternative heating.

Customers seem satisfied with their natural gas service and are generally not considering a change. However, 10% are considering a change and these customers tend to be male and newer to the community most often. Those who are considering are also most likely to do it within the next 3 years.





Base: All respondents (n=307)
Q17. Are you considering switching from a natural gas service to an alternative heating source (such as heat pump)?

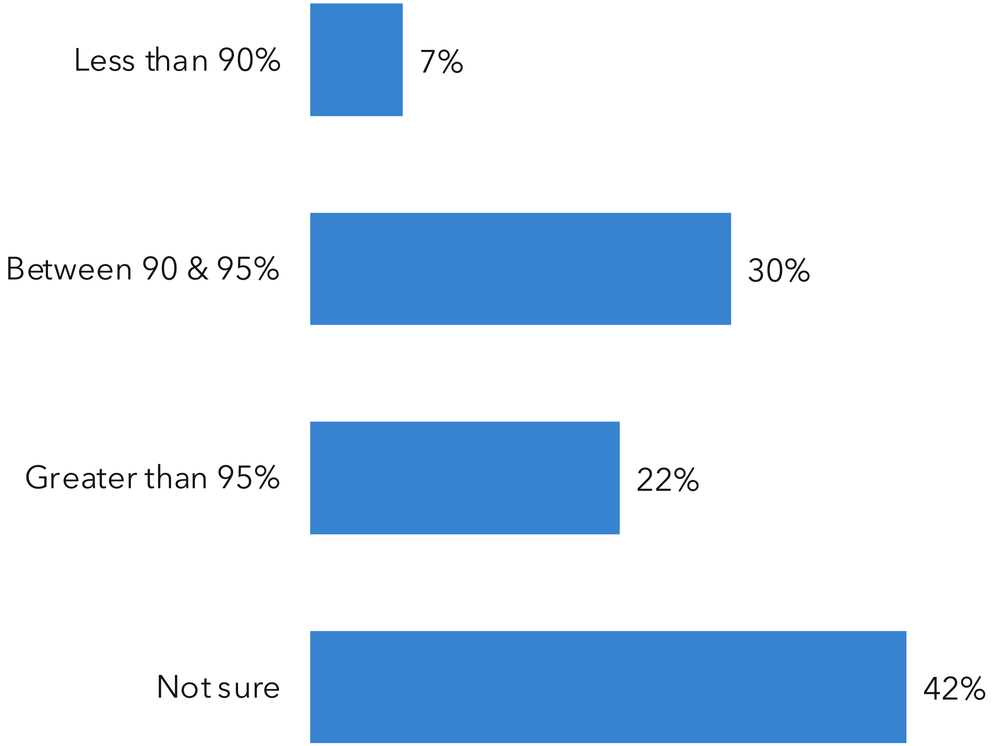
Base: All respondents (n=27)*
Q18. In how many years would you expect to make a change? *Caution – sample size <30

Efficiency ratings are typically greater than 90% but many customer are unsure.

Stone Olafson

Furnace efficiency tends to be greater than 90% with very few that are less efficient. Interestingly though, over 40% of customers are unsure what their furnace efficiency rating is.

Ensuring customers are aware of and understand their furnace efficiency ratings, and how it can affect their energy costs may build upon satisfaction and trust.



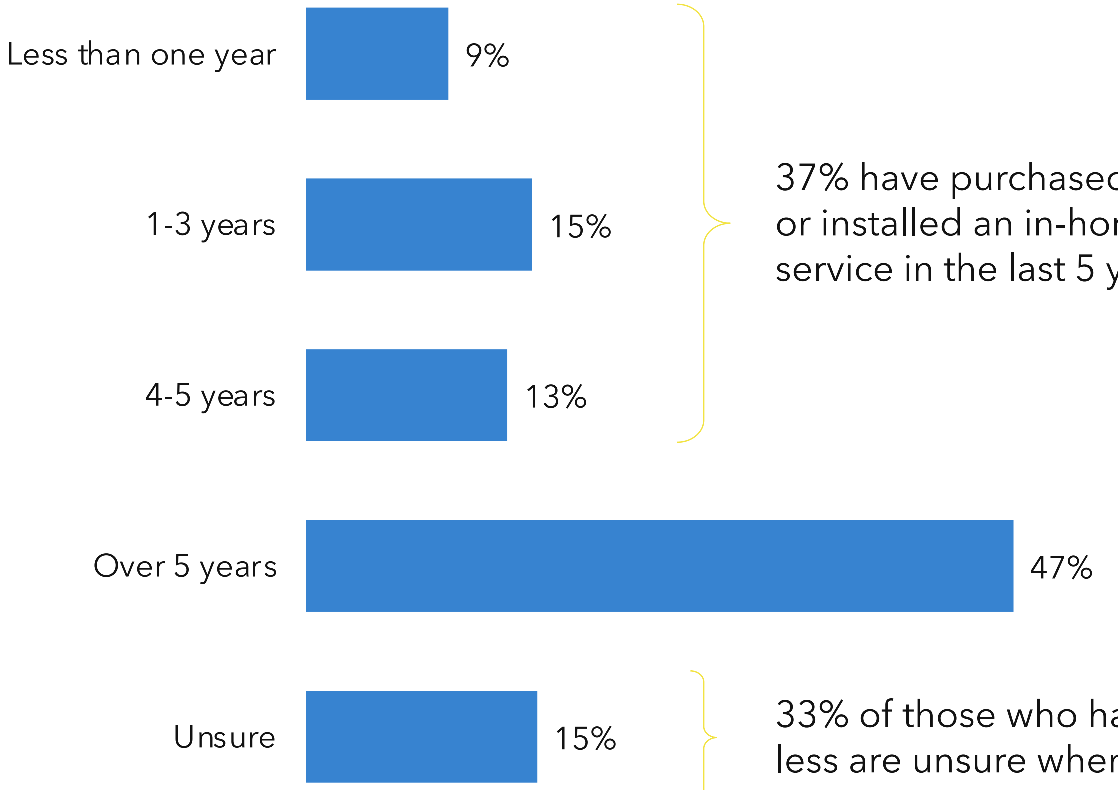
EPCOR

Base: All respondents (n=307)
Q15. What is your furnace efficiency rating?

Most customers have not made any changes to their heating solution in over 5 years.

Stone Olafson

Nearly half of survey respondents have not purchased, changed, or installed an in-home heating solution within the last 5 years. Naturally, of those who have, most have lived in their community for over 5 years.



37% have purchased, changed, or installed an in-home heating service in the last 5 years

33% of those who have lived in the community for 5 years or less are unsure when their heating solution was last changed.

EPCOR

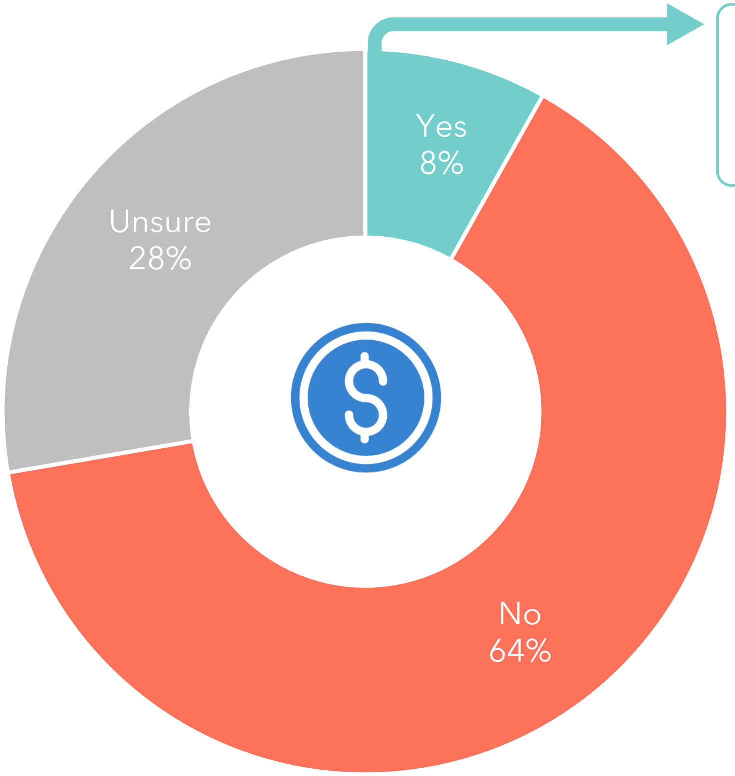
Base: All respondents (n=307)
Q16. Thinking more about energy in your home, when did you last purchase, change, or install your in-home heating solution?

Detailed Findings

Cost of service and future investment

Customers are generally unwilling to increase their monthly bills to prevent service interruptions.

Although some are willing to pay slightly more to help prevent service interruptions, the majority would be hesitant to increase monthly payments as affordability remains a top concern.



Those 55 years and older are slightly more willing to pay than younger generations

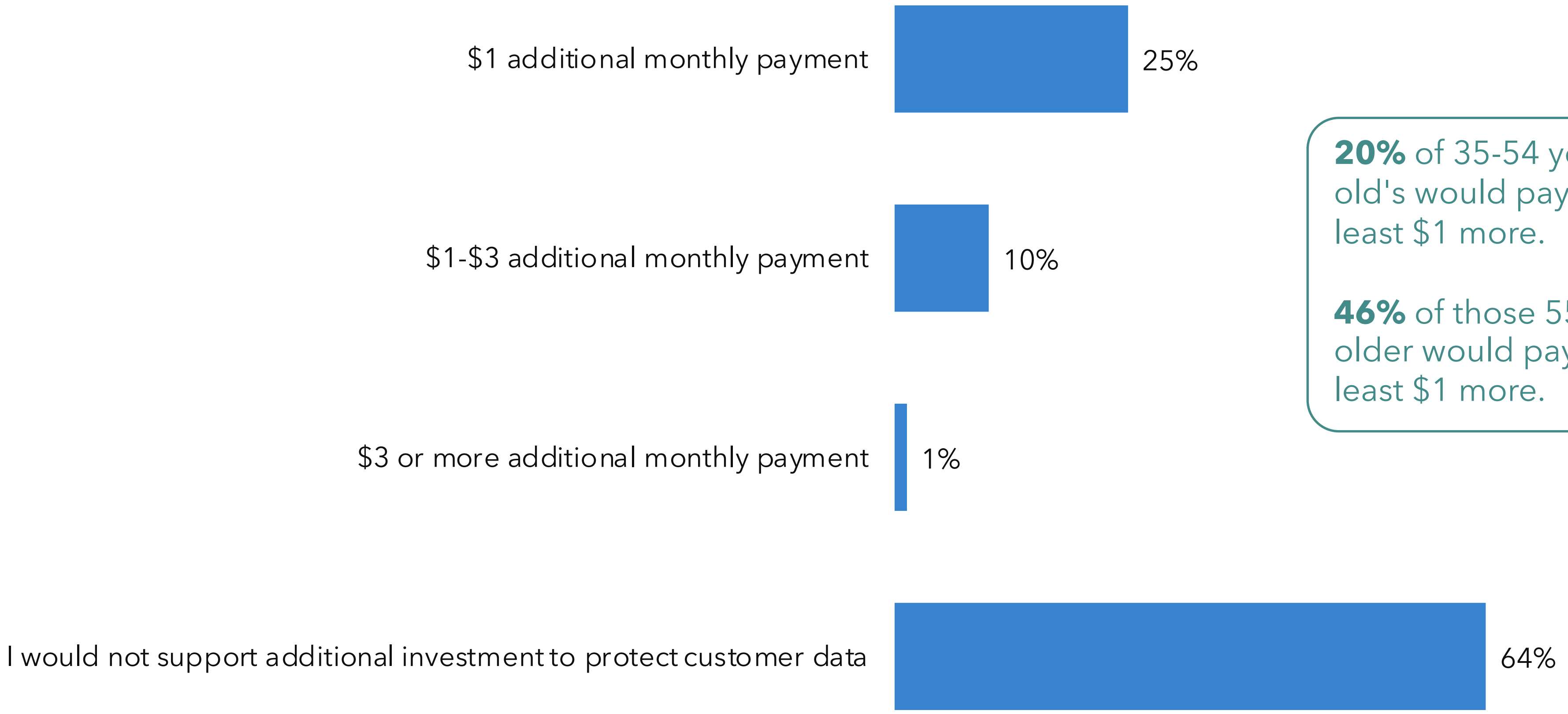
Base: All respondents (n=307)

Q8. The natural gas system has many areas where it ends without looping back to the rest of the system, like cul-de-sacs. As a result, customers in those areas may experience service interruptions when system repairs are needed. Thinking about your natural gas service, would you be willing to pay slightly more for your service to improve the reliability of your service?

Investment in data privacy has some support, particularly from an older generation.

Stone Olafson

A similar story when considering data privacy, most customers are not in support of additional investment at all. However, older generations are most inclined to pay an additional dollar for more robust cybersecurity measures.



20% of 35-54 year old's would pay at least $1 more.

46% of those 55 or older would pay at least $1 more.

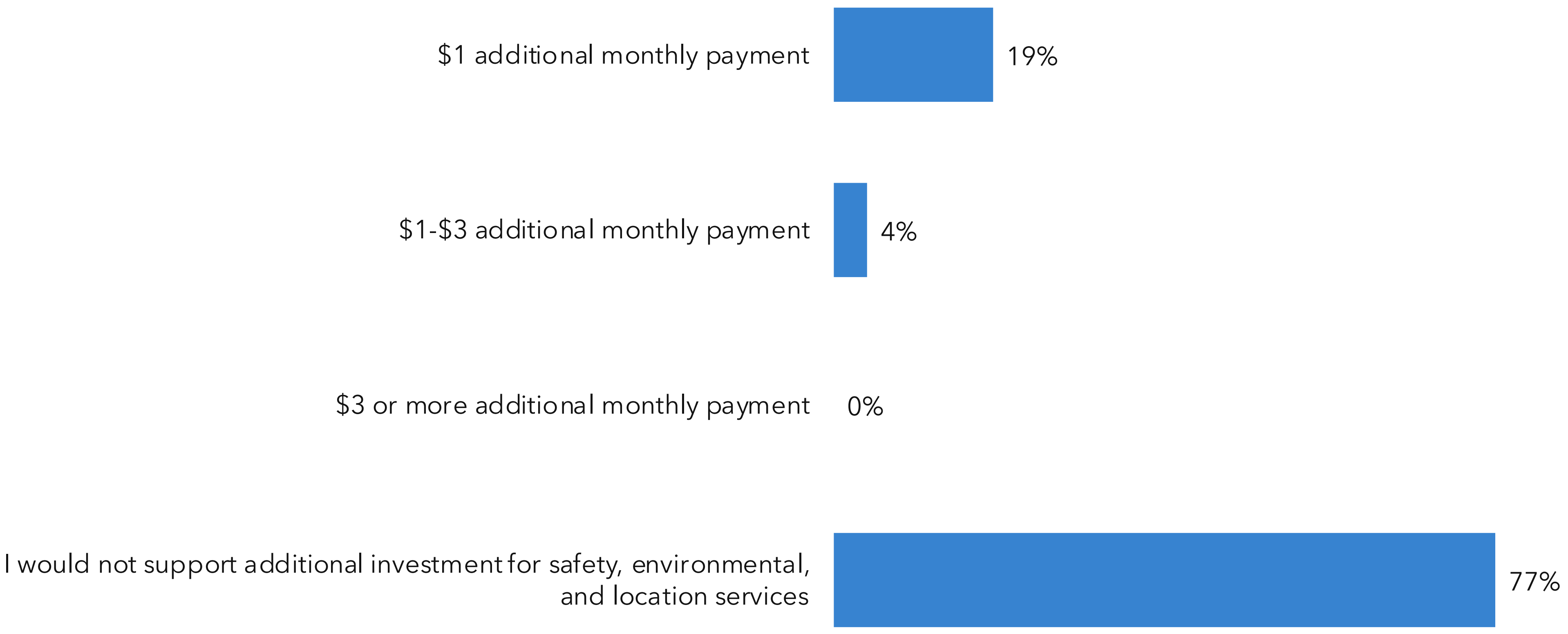
EPCOR

Base: All respondents (n=307)
Q9. Protecting customer information is a top priority for EPCOR. To protect against cybersecurity threats and ensure data privacy, which of the following would you support, considering the higher the monthly payment, the more possible investment into this priority?

Additional costs associated with infrastructure are supported by near a quarter of the market.

Stone Olafson

Fewer customers are willing to pay for any increase in cost of gas infrastructure, however there is interest for 23% of the market. This priority may feel more removed from the individual consumer than data privacy and service interruptions which show immediate value.



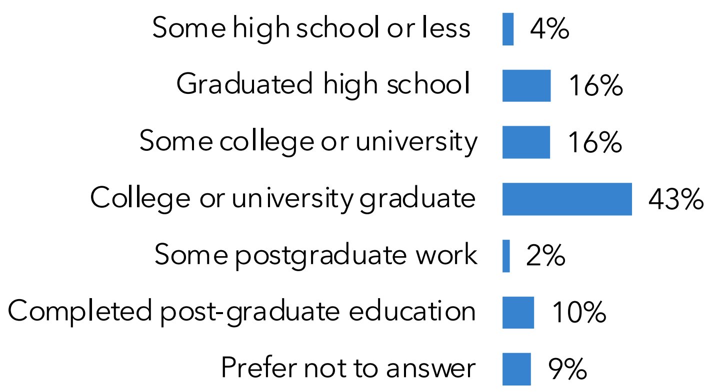
Base: All respondents (n=307)
Q10. Constructing new homes is a priority for our provincial government. To support this, EPCOR provides safety and environmental services to locate existing, or install new gas infrastructure. To help meet the growing demand of local construction, which of the following would you support, considering the higher the monthly payment, the more possible investment into this priority?

Respondent Profile

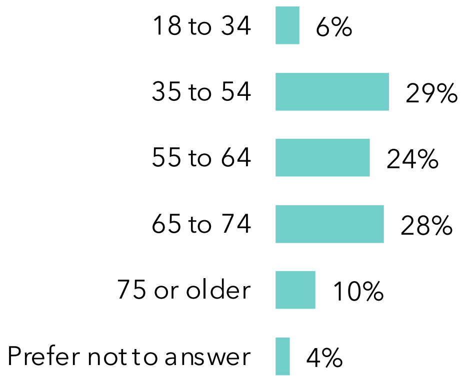
Respondent Profile

Stone Olafson

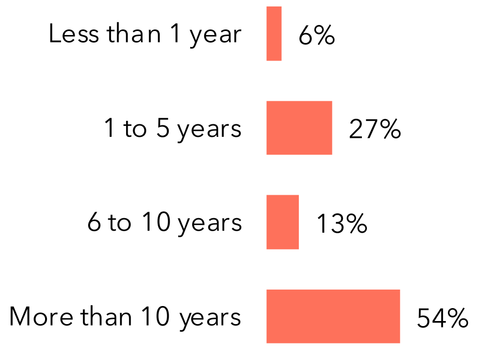
Education



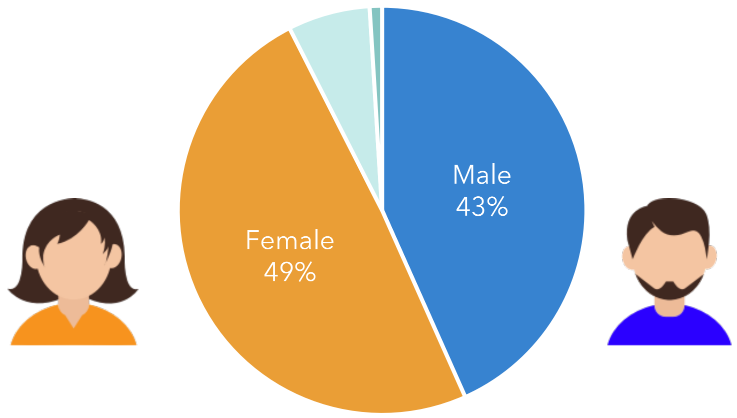
Age



Time in Community

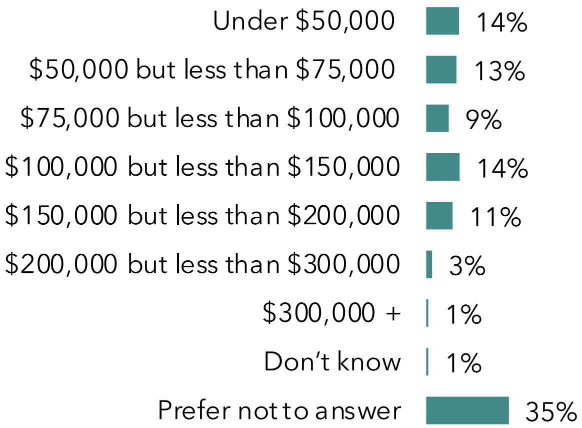


Gender

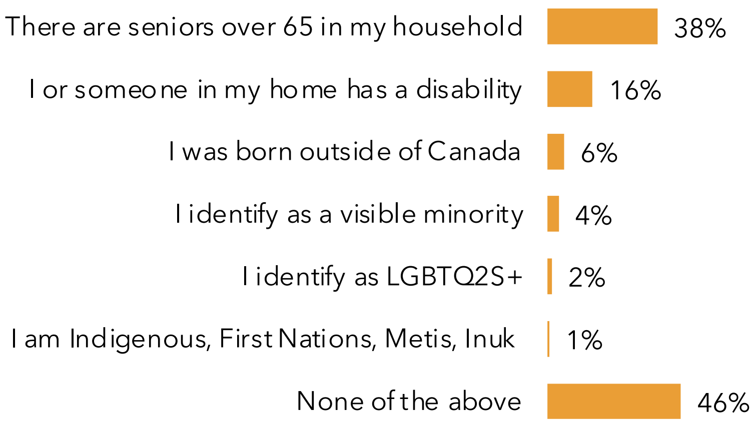


Prefer to Self-Identify: 1%
Prefer Not to Answer: 7%

Income



Profile Characteristics



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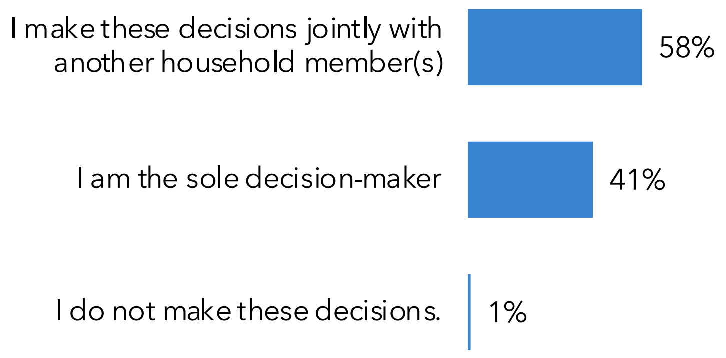
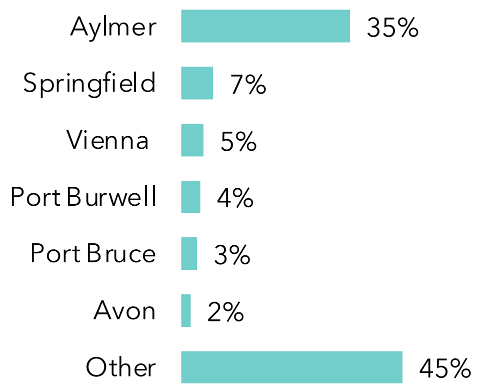
Respondent Profile - Continued

Stone Olafson

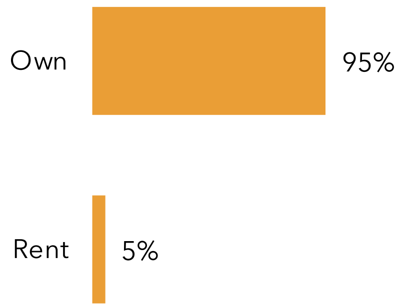
Decision Maker In Household



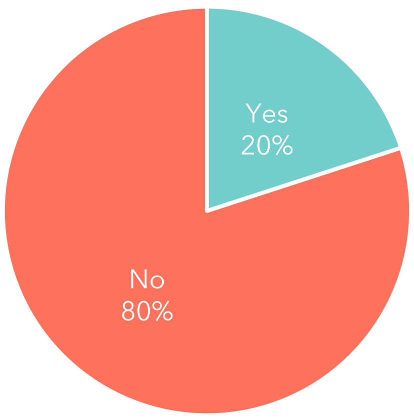
Community of Residence



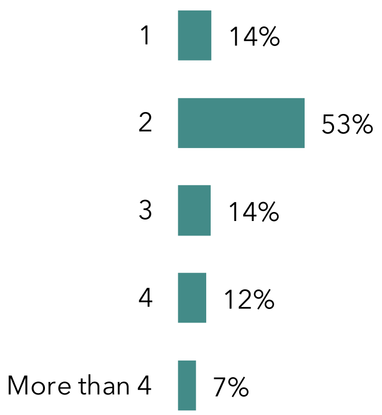
Own / Rent



Children in Household



Number in Household



EPCOR

Understanding people.

It's what we do.

Stone — Olafson

Questions or Comments?

Please contact jason@stone-olafson.com

ENGLP – Customer Connection Policy

EPCOR Natural Gas L.P. New Connection Policy
(the “**Policy**”)

Table of Contents

1.0 Definitions

"**BTU**" means British Thermal Unit.

"**Custome**r" means the individual customer or contractor requesting connection.

"**DCF Analysis**" means discounted cash flow analysis, which measures the economic Feasibility of a project based on NPV and PI.

"**HST**" means Harmonized Sales Tax.

"**Large Volume Customer**" means any Customer that has 1,000,000 BTUs or more of equipment per service.

"**NPV**" means Net Present Value.

"**OEB**" means the Ontario Energy Board.

"**PI**" means profitability index.

"**Utility**" means EPCOR Natural Gas Limited Partnership, an affiliate of EPCOR Utilities Inc.

"**WACC**" means the weighted average cost of capital as approved by the OEB.

2.0 Introduction

2.1 The purpose of this Policy is to present the current procedures and policies for determining the feasibility of the Utility's system expansion and community expansion projects. These procedures and policies are adopted to comply with the OEB's "Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario", reported under EBO 188 dated January 30, 1998 ("**EBO 188**").

2.2 This Policy includes sections regarding the Utility's Customer Connection Policies, Customer Contribution and Refund Policies and Method for Economic Feasibility Assessment.

3.0 Customer Connection Policy

3.1 The Utility has discretion over this Policy and determining the costing methods herein.

3.2 The Utility uses a combined approach to manage its system expansion activities, ensuring that the required profitability standards are achieved at both the individual project and the portfolio level.

3.3 The Utility manages its expansion projects to achieve a PI of greater than 1.0 as required by the OEB under EBO 188.

3.4 The minimum PI required for individual projects is 1.0. For projects with a PI less than 1.0, the customer shall be required to pay a Contribution-in-Aid-of-Construction ("**CIAC**") to bring the project up to the required PI level.

3.5 During construction and operation of each of the Utility's projects, the Utility shall comply with the "OEB Environment Guidelines for Hydro Carbon Pipelines and Facilities in Ontario".

4.0 Customer Contribution and Refund Policy

4.1 A CIAC may be obtained for projects having a negative NPV or a PI less than 1.0. The contribution should be sufficient to bring the project PI up to a required level. HST is added to all CIAC payments.

4.2 The feasibility of residential customers connecting to existing mains is based on customers' revenue allowance ("**Revenue Allowance**") and service costs ("**Service Costs**"), which are individually estimated for these services. Revenue Allowance is driven by customers' consumption and represents the amount of capital EPCOR can invest to achieve the required feasibility threshold (i.e. PI of 1.0). The Revenue Allowance is determined by taking the present value of a customer's future revenue over 40 years. The Service Cost is the estimated capital cost for each infill service connection. Methods of estimation are described at section 7.2. The amount of Service Cost in excess of the Revenue Allowance is the CIAC amount that is recovered from customers before service installation. A CIAC will be charged for installations to recover a shortfall for installations greater than the minimum threshold as included in ENGLP's rate order.

4.3 Where the use of a proposed facility is dominated by a single Large Volume Customer, the proposed facility shall be considered a dedicated facility for CIAC purposes, which requires that facility to pay the entirety of the CIAC, if applicable. The dominant customer may be required to pay a contribution to result in a project NPV of zero or a PI of 1.0. The CIAC amounts are subject to added HST.

4.4 Customers may request CIAC refunds when the actual customer count on the system expansion exceeds the original forecast. For all general service customers that are not Large Volume Customers, these refunds are processed at the end of five (5) years from the date of construction. The system expansion project is then re-evaluated with the actual customer count to determine a revised contribution that is required to bring the NPV to the original targeted level. The difference between the revised contribution amount and the actual CIAC paid by customers is the total amount to be refunded to original customers. Refunds are made based on the proportionate contribution of customers.

4.5 CIAC refunds are provided only for the specific piece of main put into service; no refunds are payable for customers added downstream of the specific piece of main. No interest is payable, and only customers who made a contribution are eligible for a refund. In order to be eligible for a refund, the customer must be consuming natural gas at the address for which the refund is being claimed. If the customer moves locations, they are responsible for notifying the Utility of the new address. Refunds for Large Volume Customers will be determined based on a re-evaluation of the system expansion project, taking into consideration extra investment and additional load brought on within five (5) years to the specific piece of main constructed to serve the initial customer(s). Similar to system expansions, refunds for Large Volume Customers will be evaluated subject to a customer's request.

5.0 System Expansion Portfolios – Accountability

5.1 The Utility, in its discretion, evaluates all system expansion projects in a test year and ensures they are designed to achieve a portfolio PI of at least 1.1. All new customers attaching to new and existing mains are included in the Utility's investment portfolio.

6.0 Estimating Inputs for Economic Feasibility Assessment

6.1 The method used to determine the parameters that make up the economic feasibility assessment include capital cost, operation and maintenance ("O&M") expenses, and distribution revenues associated with a system expansion project. These inputs are discounted at the Utility's WACC to carry out the DCF analysis which measures economic feasibility of a project based on NPV and PI. This determination is done at the Utility's discretion.

7.0 Capital Cost Estimation

7.1 The Utility, at its own discretion, estimates capital cost for different types of projects based on the unique attributes of each project, including an estimation based on any third-party contractor estimates received in alignment with ENGLP's procurement policy. The objective is to derive estimates that are closely aligned with the unique parameters of each project mitigating risk for both parties.

7.2 The following is a summary of various estimation techniques and the project types to which they are applied:

7.2.1 Capital cost estimates are based on a regionally-specific estimate that relies on historical actual data of similar services installed. It can also be a specific field estimate where no historical data are available that is representative of the geographic area. In instances where known geographical or geological factors (e.g. rock, depth of main, etc.), in ENGLP's discretion, have influenced capital costs, ENGLP will utilize pricing for those factors to inform the estimate.

7.2.2 If a main is oversized to meet future growth potential, the capital estimate will be proportioned based on the applicant's pro-rated share.

7.2.3 An incremental overhead allowance is added to the cost of mains and services and is incorporated in the feasibility analysis of all projects.

8.0 Consumption and Revenue

8.1 For subdivision and residential connections, consumption is estimated based on historical rate class usage.

8.2 For commercial and industrial connections, a technical information sheet will be provided to the Customer for execution, and must be returned to ENGLP. This technical information sheet contains consumption of various appliances installed at the premises.

8.3 For Large Volume Customer connections, consumption information must include monthly volumes, unless agreed upon in writing by the Utility and the customer's contract daily demand.

8.4 The Utility, at its own discretion, calculates revenue, based on the input consumption profile and the most recent OEB-approved revenue rates.

9.0 Customer Attachment and Revenue Horizon

9.1 The maximum customer attachment horizon for residential, commercial and industrial connections that are not Large volume Customers is ten (10) years. The maximum revenue horizon is 40 years from the in-service date of the initial mainline.

9.2 For Large Volume Customers, the maximum customer attachment horizon is ten (10) years. The maximum revenue horizon is 20 years from the customers' initial service date.

9.3 A project specific revenue horizon is used when the project life cycle is deemed shorter than 20 years.

10.0 Marginal Operating and Maintenance Expenses

10.1 The Utility's incremental O&M cost is based on historical costs per rate class in combination with any identified incremental costs specific to the project.