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Enbridge Gas Inc.
500 Consumers Road
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Canada

VIA RESS and EMAIL

October 15, 2020

Ms. Christine Long
Board Secretary
Ontario Energy Board
P.O. Box 2319,
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Ms. Long:

Re: EB-2020-0181 Enbridge Gas Inc. ("Enbridge Gas")
2021 Rates – Application and Evidence (Incremental Capital Module)

Please find attached an Application by Enbridge Gas Inc. ("Enbridge Gas" or "EGI") for interim and final orders of the Ontario Energy Board ("OEB" or the "Board") under section 36 of the *Ontario Energy Board Act, 1998* approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of natural gas, commencing January 1, 2021. Specifically, as set out in this Application, Enbridge Gas applies for approval of unit rates related to its 2021 Incremental Capital Module ("ICM") requests.

Background

On August 30, 2018, in the MAADs Decision (EB-2017-0306/0307), the Board approved a rate setting mechanism (Price Cap IR) for Enbridge Gas, which sets out a multi-year incentive rate-setting mechanism ("IRM") for the calendar year term of 2019 to 2023 (the "five year term" or the "deferred rebasing period"). The MAADs Decision confirmed that during the five-year term, distribution rates will be set separately for the Enbridge Gas Distribution ("EGD") and Union Gas ("Union") rate zones. The MAADs Decision also approved the specific treatment of various elements in the IRM including the availability of an Incremental Capital Module ("ICM") during the five-year term.

This 2021 Rate Application is the third annual rate adjustment application under the IRM approved in the MAADs Decision.

On June 30, 2020, Enbridge Gas filed supporting evidence in EB-2020-0095 in relation to the 2021 Rate Application, which includes the annual rate escalation, pass-through costs, capital pass-through adjustments and Parkway Delivery Obligation rate adjustments, referred to as Phase 1. Enbridge Gas also advised that evidence related to the request for ICM funding will be filed as Phase 2 of the 2021 Rate Application.

In its letter dated July 14, 2020 in EB-2020-0095, the OEB determined that it will process the "Phase 1" and "Phase 2" filings for the 2021 Rate Application as separate applications, rather than as discrete "phases" within a single application. The OEB has assigned a separate docket number (EB-2020-0181) for “Phase 2” of the 2021 Rate Application.

Enbridge Gas is therefore filing this separate Application for its 2021 ICM requests. With this Application, Enbridge Gas is seeking Board approval for ICM funding for three projects in 2021 – the St Laurent NPS 12 Replacement in the EGD rate zone, and the London Line Replacement Project and the Sarnia Industrial Reinforcement Project in Union rate zones. The ICM evidence including the appendices are filed as Exhibit B, Tab 2, Schedule 1.

Also, in accordance with the Board’s directive in the MAADs Decision, Enbridge Gas is filing a consolidated Utility System Plan (including an Asset Management Plan and a Customer Engagement Study) for the ICM requests with this Application. The Utility System Plan is filed as Exhibit C, Tab 1, Schedule 1. The Asset Management Plan and the Customer Engagement study are filed as Exhibit C, Tab 2, Schedule 1 and Exhibit C, Tab 3, Schedule 1 respectively.

Please contact the undersigned if you have any questions.

Yours truly,

(Original Digitally Signed)

Rakesh Torul
Technical Manager,
Regulatory Applications

cc: David Stevens, Aird and Berlis LLP
EB-2020-0181 Intervenors

EXHIBIT LIST

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ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF an Application by Enbridge Gas Inc., pursuant to section 36(1) of the *Ontario Energy Board Act, 1998*, for an order or orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas as of January 1, 2021.

APPLICATION

1. The Applicant, Enbridge Gas Inc. (“Enbridge Gas”, or “EGI”) is an Ontario corporation with its head office in the City of Toronto. It carries on the business of selling, distributing, transmitting, and storing natural gas within Ontario. Enbridge Gas was formed effective January 1, 2019, upon the amalgamation of Enbridge Gas Distribution Inc. (“EGD”) and Union Gas Limited (“Union”).

2. Enbridge Gas hereby applies to the Ontario Energy Board (the “OEB” or the “Board”), pursuant to section 36 of the *Ontario Energy Board Act, 1998*, as amended (the “Act”) for interim and final Orders approving or fixing just and reasonable rates for the sale, distribution, transmission, and storage of gas commencing January 1, 2021. Specifically, as set out herein, Enbridge Gas applies for approval of unit rates related to its 2021 Incremental Capital Module (“ICM”) requests.

3. On August 30, 2018, in the MAADs Decision[1], the Board approved a rate setting mechanism (Price Cap IR) for Enbridge Gas, which sets out a multi-year incentive rate-setting mechanism ("IRM") for the calendar year term of 2019 to 2023 (the "five year term" or the "deferred rebasing period"). The MAADs Decision confirmed that during the five year term, distribution rates will be set separately for the EGD and Union rate zones. The MAADs Decision also approved the specific treatment of various elements in the IRM including the availability of an ICM during the five year term.

4. The 2021 Rate Application (EB-2020-0095) is the third annual rate adjustment application under the IRM approved in the MAADs Decision. In its 2021 Rate Application, Enbridge Gas proposed to continue with a bifurcated approach, similar to the 2020 Rate Application, where distribution rates relating to the IRM adjustments would be processed and adjudicated first (as "Phase 1") and matters related to ICM funding would be addressed in "Phase 2" of the EB-2020-0095 proceeding.

5. On June 30, 2020, Enbridge Gas filed supporting evidence for "Phase 1" of its 2021 Rate Application (EB-2020-0095) to address the IRM related elements which included the annual rate escalation, pass-through costs, capital pass-through adjustment and Parkway Delivery Obligation rate adjustment. On October 8, 2020, Enbridge Gas and all interested parties filed a Settlement Proposal that resolved all matters in "Phase 1" of the 2021 Rate Application, and includes draft Interim Rate Orders for updated 2021 rates to be effective January 1, 2021.

6. In its letter dated July 14, 2020 in EB-2020-0095, the OEB determined that it will process the "Phase 1" and "Phase 2" filings for the 2021 Rate Application as

[1] EB-2017-0306/0307.

separate applications, rather than as discrete “phases” within a single application. The OEB has assigned a separate docket number (EB-2020-0181) for “Phase 2” of the 2021 Rate Application.

7. Enbridge Gas is therefore filing this separate Application for its 2021 ICM requests. With this Application, Enbridge Gas is seeking Board approval for ICM funding for three projects in 2021 – the St Laurent NPS 12 Replacement in the EGD rate zone, and the London Line Replacement Project and the Sarnia Industrial Reinforcement Project in Union rate zones. Collectively, these projects are referred to as the “2021 ICM Projects”. The ICM evidence including the appendices are filed as Exhibit B, Tab 2, Schedule 1.[2]

8. Also, in accordance with the Board’s directive in the MAADs Decision[3], Enbridge Gas is filing a consolidated Utility System Plan (including an Asset Management Plan and a Customer Engagement Study) for the ICM requests with this Application. The Utility System Plan is filed as Exhibit C, Tab 1, Schedule 1. The Asset Management Plan and the Customer Engagement study are filed as Exhibit C, Tab 2, Schedule 1 and Exhibit C, Tab 3, Schedule 1 respectively.

APPROVAL REQUESTS

9. The specific approvals sought in this Application are as follows:

- The requests for ICM funding for the 2021 ICM Projects, including the ICM unit rates beginning in 2021 for the duration of the deferred rebasing period to recover the total revenue requirement of the 2021 ICM Projects from 2021 to 2023;

[2] In order to maintain consistency with prior applications related to ICM requests during the five year term, Enbridge Gas has labeled the ICM request evidence as Exhibit B-2-1 (meaning that there are no B-1-1 exhibits in this filing).
[3] EB-2017-0306/EB-2017-0307, Decision and Order, August 30, 2018, pp.32-34.

- Final rates for the year commencing January 1, 2021, including the full-year impact of all items included in the "Phase 1" of the 2021 Rate Application in EB-2020-0095 and the ICM requests in this Application; and
- The determination of all other issues that bear upon the Board's approval or fixing of just and reasonable rates for the sale, distribution, transmission, and storage of gas by Enbridge Gas for the year commencing January 1, 2021.

10. Enbridge Gas further applies to the Board pursuant to the provisions of the Act and the Board's Rules of Practice and Procedure for such final, interim or other Orders and directions as may be appropriate in relation to the Application and the proper conduct of this proceeding.

11. This Application is supported by written evidence and may be amended from time to time as circumstances require.

12. The persons affected by this Application are the customers resident or located in the municipalities, police villages and First Nations reserves served by Enbridge Gas, together with those to whom Enbridge Gas sells gas, or on whose behalf Enbridge Gas distributes, transmits or stores natural gas.

13. Approval of the 2021 ICM funding set out in this Application will result in the following bill impacts:

    - The bill impact associated with the 2021 ICM funding request for a typical Rate 1 residential customer consuming 2,400 m^3 annually in the EGD rate zone is an increase of $0.11.

- The bill impact associated with the 2021 ICM funding request for a typical Rate M1 residential customer consuming 2,200 m^3 annually in the Union South rate zone is an increase of $2.71.
- There is no bill impact associated with the 2021 ICM funding request for a typical Rate 01 residential customer in the Union North rate zone as there is no ICM project applicable to this rate zone.

14. The address of service for Enbridge Gas is:

Enbridge Gas Inc.

500 Consumers Road
Willowdale, Ontario
M2J 1P8

Attention:	Mark Kitchen Director, Regulatory Affairs
Telephone:	(519) 436-5275
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- and -

Aird & Berlis LLP

Brookfield Place, P.O Box 754
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Toronto, Ontario
M5J 2T9

Attention:	David Stevens
Telephone:	(416) 863-1500
Fax:	(416) 863-1515
Email:	dstevens@airdberlis.com

DATED October 15, 2020, at Toronto, Ontario

ENBRIDGE GAS INC.

(Original Digitally Signed)

Rakesh Torul
Technical Manager,
Regulatory Applications

ENBRIDGE GAS INC. 2021 RATE APPLICATION
INCREMENTAL CAPITAL MODULE

1. This evidence supports Enbridge Gas's request for incremental capital module ("ICM") funding for capital investments that are not funded through existing rates. The Board approved the use of an ICM to fund incremental capital during Enbridge Gas's 2019-2023 deferred rebasing period as part of the MAADs Decision.[1] Enbridge Gas received approval for ICM funding from the Board in 2019 and 2020. The Board approved the Kingsville Reinforcement Project and Stratford Reinforcement Project as part of the 2019 Rates Decision[2], and the Don River Replacement Project and the Windsor Line Project as part of the 2020 Rates Decision[3]. In this application, Enbridge Gas is seeking ICM funding for three projects in 2021 – the St. Laurent NPS 12 Replacement in the EGD rate zone, and the London Line Replacement Project and the Sarnia Industrial Reinforcement Project in the Union South rate zone.

2. This evidence is organized as follows:
    1. Capital Planning Overview
    2. Eligibility for Incremental Capital
        - 2.1 Materiality
        - 2.2 Need
        - 2.3 Prudence
    3. Customer Consultation
    4. Calculation of Revenue Requirement
    5. Cost Allocation
    6. ICM Unit Rates

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[1] EB-2017-0306/EB-2017-0307, Decision and Order, August 30, 2018. The Decision and Order was later amended by the Board on September 17, 2018 with no material changes.
[2] EB-2018-0305, Decision and Order, September 12, 2019.
[3] EB-2019-0194, Decision and Order, May 14, 2020.

7. ICM Bill Impacts

1. <u>CAPITAL PLANNING OVERVIEW</u>

3. Enbridge Gas filed a Utility System Plan ("USP")[4] which included an Asset Management Plan ("AMP") for each of the EGD and Union rate zones[5] as part of its 2019 Rates Application (EB-2018-0305) and its 2020 Rates Application (EB-2019-0194) in support of its ICM requests. In the 2019 Rates Decision, the Board found the USP and AMPs acceptable for the purposes of considering the ICM funding requests.[6]

4. As directed in the MAADs Decision[7], Enbridge Gas is filing a consolidated USP and AMP to support the ICM requests included in the 2021 Rates Application. The AMP reflects Enbridge Gas's asset plan for the next five years, with assets for the EGD and Union rate zones being maintained separately for capital planning purposes through the end of 2025. The AMP identifies how Enbridge Gas plans, manages and develops the distribution, transmission, and storage systems, and determines the capital investment requirement while balancing risk, performance and cost. The identification of the need for a capital expenditure can either be to satisfy a growth requirement or to resolve degraded condition or performance of an existing asset. In either case, the process to create a new asset is the same. Through the budgeting process, the risks that each project is mitigating are re-evaluated and endorsed.

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[4] EB-2018-0305, Exhibit C1, Tab 1, Schedule 1.
[5] EB-2018-0305, Exhibit C1, Tab 2, Schedule 1 for the EGD rate zone and Exhibit C1, Tab 3, Schedule 1 for the Union rate zones.
[6] EB-2018-0305, Decision and Order, September 12, 2019, p. 19. The USP and AMPs were implicitly accepted for ICM purposes in the 2020 Rates Application.
[7] EB-2017-0306/EB-2017-0307, Decision and Order, August 30, 2018, pp. 33-34.

5. As there are finite resources to complete capital projects, projects are selected for the AMP on the basis of their relative priority. All projects are evaluated and prioritized/optimized to ensure that capital resources are employed to address the highest priority items across all asset categories.

6. Enbridge Gas's methodology for project prioritization/optimization considers risk, customer input and preferences, resource availability and asset portfolio strategies. More details on the project prioritization/optimization can be found in Enbridge Gas's AMP.

7. The historical and forecast capital investments by category for the 2016 to 2025 period are shown in Table 1 for the EGD rate zone and Table 2 for the Union rate zones. These capital investments will allow Enbridge Gas to continue to meet customer needs and ensure safe and reliable delivery of natural gas to customers.

Table 1

Capital Expenditures[8] by category (2016-2025) – EGD Rate Zone ($ millions)

Line No.	Category	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Forecast
		(b)	(c)	(d)	(e)	(e)
1	General Plant	82.6	48.1	47.3	70.4	61.0
2	System Access[9]	118.3	109.3	108.9	151.1	126.9
3	System Renewal	109.1	102.2	92.3	110.4	161.8
4	System Service	127.1	20.2	22.9	23.9	25.9
5	Total Overhead	156.4	148.1	140.2	151.6	140.2
6	**Total - EGD Rate Zone**	**593.5**	**427.8**	**411.6**	**507.4**	**515.8**

Line No.	Category	2021 Budget	2022 Budget	2023 Budget	2024 Budget	2025 Budget
		(f)	(g)	(h)	(i)	(j)
1	General Plant	102.4	60.7	111.8	55.2	59.7
2	System Access[9]	167.6	164.6	223.7	167.6	165.7
3	System Renewal	259.8	403.7	215.8	461.5	268.3
4	System Service	50.5	32.2	28.0	39.4	88.7
5	Total Overhead[10]					
6	**Total - EGD Rate Zone**	**580.3**	**661.2**	**579.3**	**723.7**	**582.4**

[8] Capital expenditure shown for 2016-2018, In-Service for 2019-2025.
[9] System access capital does not include Community Expansion and Compressed Natural Gas.
[10] Overheads included with projects costs for 2021-2025

Table 2

Capital Expenditures[11] by category (2016-2025) – Union Rate Zones ($ millions)

Line No.	Category	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Fcast
		(b)	(c)	(d)	(e)	(e)
1	General Plant	44.8	42.8	48.0	51.8	28.4
2	System Access[12]	105.6	96.2	83.5	104.4	97.8
3	System Renewal	90.1	94.1	99.4	106.4	191.3
4	System Service	720.5	405.8	201.2	162.1	106.2
5	Total Overhead	77.2	78.6	81.0	83.1	101.7
6	**Total - Union Rate Zones**	**1,038.2**	**717.5**	**513.1**	**507.8**	**525.4**

Line No.	Category	2021 Budget	2022 Budget	2023 Budget	2024 Budget	2025 Budget
		(f)	(g)	(h)	(i)	(j)
1	General Plant	55.6	56.8	78.8	72.4	91.1
2	System Access[12]	150.7	328.5	126.3	252.8	125.7
3	System Renewal	327.6	197.6	210.3	345.9	136.4
4	System Service	93.1	123.0	177.0	52.5	168.2
5	Total Overhead[13]					
6	**Total - Union Rate Zones**	**627.0**	**705.9**	**592.3**	**723.7**	**521.4**

[11] Capital expenditure shown for 2016-2018, In-Service for 2019-2025.
[12] System access capital does not include Community Expansion and Compressed Natural Gas.
[13] Overheads included with projects costs for 2021-2025

General Plant

8. General plant investments are modifications, replacements or additions to Enbridge Gas's assets that are not part of its commodity-carrying system including land and buildings, tools and equipment, fleet vehicles and electronic devices and software used to support day to day business and operations activities.

9. The historical and forecast general plant capital expenditures are presented in Appendix A in this exhibit, Table A for EGD rate zone and Table B for Union rate zones.

System Access

10. System access investments are additions and modifications (including asset relocation) to the Enbridge Gas distribution system that the utility is obligated to perform in order to provide a customer or group of customers with access to natural gas services via the distribution and transmission systems. System Access capital expenditures are driven mainly by Customer Growth, Natural Gas Vehicles (NGV) and third party driven rebillable relocation projects.

11. The historical and forecast system access capital expenditures are presented in Appendix A in this exhibit, Table C for EGD rate zone and Table D for Union rate zones.

System Renewal

12. System renewal investments involve replacing and/or refurbishing system assets to extend the original service life of the assets and thereby maintain the ability of Enbridge Gas's system to provide customers with natural gas services. System Renewal capital expenditures are mainly driven by Main Replacements, Meter

Exchanges/Replacements, Compressor Equipment, Regulator Refits and Service Relays.

13. The historical and forecast system renewal capital expenditures are presented in Appendix A in this exhibit, Table E for EGD rate zone and Table F for Union rate zones.

System Service

14. System service investments are modifications to Enbridge Gas's distribution system to ensure the system continues to meet distributor operational objectives. System service capital expenditures are mainly driven by transmission and distribution system growth, reinforcement projects and integrity initiatives.

15. The historical and forecast system service capital expenditures are presented in Appendix A in this exhibit, Table G for EGD rate zone and Table H for Union rate zones.

2. ELIGIBILITY FOR ICM CAPITAL

16. In the MAADs Decision, the Board confirmed the availability of ICM funding for Enbridge Gas.[14] As set out in section 4.1.5 of the "Report of the Board – New Policy Options for the Funding of Capital Investments: The Advanced Capital Module, EB-2014-0219", to be eligible for recovery, capital projects must meet the following criteria: materiality, need and prudence. Each of these criteria is described below in relation to Enbridge Gas's ICM funding request for 2021.

[14] EB-2017-0306/EB-2017-0307, Decision and Order, August 30, 2018, pp.30-34.

2.1 MATERIALITY

Materiality Threshold Test

17. As defined by the Board, "a capital budget will be deemed to be material, and as such reflect eligible projects, if it exceeds the Board-defined materiality threshold. Any incremental capital amounts approved for recovery must fit within the total eligible incremental capital amount (as defined in this ACM Report) and must clearly have a significant influence on the operation of the distributor; otherwise they should be dealt with at rebasing."[15]

18. The Board determined the formula to be used to calculate the materiality threshold as follows:

Threshold Value $= 1 + [(RB/d) * (g + PCI * (1 + g))] * ((1 + g) * (1 + PCI))^{n-1} + 10\%$

Where:

RB = Rate base included in base rates ($)

d = Depreciation expense included in base rates ($)

g = Growth factor (%)

PCI = Price cap index (%)

n = Number of years since rebasing

19. The Board's ICM materiality threshold calculation results in a 2021 threshold value of $567.3 million for the EGD rate zone and $474.2 million for the combined Union rate zones. The materiality threshold establishes the minimum capital expenditures a utility must fund through base rates. The maximum eligible incremental capital investment for ICM funding is the amount of forecast capital expenditures in the year

[15] EB-2014-0219 Report of the OEB – New Policy Options for the Funding of Capital Investments: The Advanced Capital Module, September 18, 2014, p.17.

in excess of the threshold value. The calculation of the ICM materiality threshold value for EGD and Union rate zones is provided in Table 3 below.

Table 3

ICM Threshold Capital Expenditure Calculation by Rate Zone

Line No.	Particulars ($ millions)	EGD	Union
		(a)	(b)
1	Year	2021	2021
2	Base Year	2018	2013
3	Number of Years since rebasing (n)	3	8
4	Price Cap Index (PCI) (%)	1.70%	1.70%
5	Growth Factor (g) (%)	1.73%	1.46%
6	Dead Band (%)	10%	10%
7	Rate Base (RB)	6,246	5,331[16]
8	Depreciation (d)	305	239[17]
9	Threshold Value (%)	186%	199%
10	Threshold Value	567.3	474.2

A description of the Price Cap Index, growth factor, and rate base and depreciation amounts used in the threshold calculation are provided below.

[16] As per the MAADs Decision, the rate base and depreciation associated with projects that were found eligible for capital pass-through treatment during Union's 2014-2018 IRM term are added to the 2013 Board approved rate base and depreciation.
[17] *Ibid.*

<u>Price Cap Index</u>

20. The Board's threshold value calculation uses PCI to recognize the increase in revenue generated through annual rate increases in a price cap plan that could be used toward capital investment.

21. Per the 2019 Rates Decision[18], Enbridge Gas has used the current year PCI of 1.7%[19] in the ICM Threshold Capital calculation for both the EGD and Union rate zones.

<u>Growth Factor</u>

22. The 2021 growth factor for the EGD rate zone has been calculated by comparing the percentage difference in annual revenues between 2019 (the most recent complete year) and 2018 as the approved base year revenues. The revenue amounts are calculated at the 2018 base year rates.

23. The 2021 growth factor for the Union rate zones has been calculated by comparing the percentage difference in annual revenues between 2019 (the most recent complete year) and 2013 as the approved base year revenues. The revenue amounts are calculated at the 2013 base year rates.

24. To determine the revenue from general service rate classes, Enbridge Gas used the actual customer count and held the normalized average consumption/average use ("NAC/AU") per customer constant with the NAC/AU in base rates. This approach is

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[18] EB-2018-0305, Decision and Order, September 12, 2019.
[19] PCI is rounded to 1 decimal place (EB-2019-0194 Decision and Interim Rate Order, December 5, 2019; Schedule A Enbridge Gas Inc. Settlement Proposal Dated November 28, 2019 Exhibit N1, Tab 1, Schedule 1, pp 8).

consistent with the calculation of general service revenue in the 2019 and 2020 growth factor calculation.

25. Enbridge Gas calculated the 2019 revenue from contract rate class using weather-actual data, as contract-rate customers are generally less weather sensitive and have a higher proportion of fixed cost recovery as compared to general service customers. Table 4 below shows the calculation of the 2021 growth factor.

Table 4
2021 Growth Factor by Rate Zone

Line No.	Particulars	($ millions)
		(a)
	EGD	
1	2019 Distribution Revenues	1,246.3
2	2018 Board-approved Distribution Revenues	1,225.1
3	2020 Growth Factor	1.73%
	Union	
4	2019 Distribution Revenues[20]	1,005.0
5	2013 Board-approved Distribution Revenues[21]	924.0
6	2020 Growth Factor (Annualized)	1.46%

[20] Includes regulated distribution and transmission revenues.
[21] *Ibid.*

26. A detailed calculation of the revenues underpinning the growth factor for each rate zone is filed as Appendix B in this exhibit.

Rate Base and Depreciation

27. The threshold calculation uses the rate base and depreciation expense last approved by the Board. Accordingly, the threshold value for the EGD rate zone is based on EGD's 2018 Board-approved rate base and depreciation.

28. Pursuant to the MAADs Decision, the threshold value for the Union rate zones is based on Union's 2013 Board-approved rate base and depreciation plus the 2019 forecast amount of rate base and depreciation associated with projects that were eligible for capital pass-through treatment and included in Union's base rates during Union's 2014-2018 IRM term.[22] The details of the rate base and depreciation amounts by rate zone are provided in Table 5 below.

Table 5

ICM Threshold Rate Base and Depreciation Expense by Rate Zone

Line No.	Particulars ($ millions)	Rate Base	Depreciation
		(a)	(b)
	EGD		
1	2013 Board-Approved	6,246	305
	Union		
2	2013 Board-Approved	3,734	196

[22] EB-2017-0306/EB-2017-0307, Decision and Order, September 17, 2018, p. 33.

3	2019 Capital Pass-Through Amounts[23]	1,597	43
4	Total	5,331	239

Eligible Capital Amount

29. Table 6 below compares the 2021 in-service capital forecast to the ICM materiality threshold by rate zone to calculate the maximum eligible incremental capital.

Table 6

Maximum Eligible Incremental Capital by Rate Zone

Line No.	Particulars ($ millions)	EGD	Union
		(a)	(b)
1	2021 In-Service Capital Forecast	580.3	627.0
2	Less: Materiality Threshold Value	567.3	474.2
3	Maximum Eligible Incremental Capital	13.0	152.8

30. The maximum eligible incremental capital for the EGD rate zone and Union rate zones is $13.0 million and $152.8 million, respectively. Enbridge Gas is seeking incremental ICM funding for specific discrete projects that fit within the maximum eligible incremental capital amount planned for each of the EGD and Union rate zones.

[23] EB-2018-0305, Exhibit F1, Tab 2, Rate Order, Working Papers, Schedule 16, pp. 4-5.

31. Table 7 below identifies the eligible capital projects and total in-service capital amounts for the ICM funding requests. Only projects that are discrete and material have been included.

Table 7

2021 Incremental Capital Funding Request by Rate Zone

Line No.	Particulars ($ millions)	Total Project In-service Amount	Total Project ICM Funding Request	Difference
		(a)	(b)	(c) = (b-a)
	2021 In-service Capital Forecast			
	EGD Rate Zone			
1	St. Laurent NPS 12 Replacement	13.0	13.0	-
	Union South Rate Zone			
2	London Line Replacement	124.0	124.0	-
3	Sarnia Industrial Line Reinforcement (1)	31.5	28.8	(2.7)
4	Total Incremental Capital Funding Request	168.5	165.8	(2.7)

Notes:

(1) The total project in-service capital amount was reduced so that the total project ICM funding request did not exceed the maximum eligible incremental capital from Table 6.

2.2 NEED

Means Test

32. A distributor must also pass the Means Test in order to be eligible for ICM funding. As defined by the Board, if a distributor's regulated return in its most recent calculation exceeds 300 basis points (bps) above the deemed return on equity embedded in the distributor's rates, the funding for any incremental capital project will not be allowed.[24]

33. Enbridge Gas filed its 2019 Earnings Sharing and Deferral and Variance Account Clearance Application on September 3, 2020, which included its 2019 actual utility results.[25] The Company has prepared its 2019 utility results on a combined basis as this is the first year that Enbridge Gas has operated as an amalgamated utility. The calculated return did not exceed 300 bps above the respective Board-approved ROE. The 2019 actual ROE was calculated to be 10.475%, which was 149.5 bps above the 2019 Board-approved ROE of 8.98%.[26] The Enbridge Gas 2019 ROE calculation, as provided in the 2019 Earnings Sharing and Deferral and Variance Account Clearance Application, is reproduced at Appendix C of this exhibit.

Discrete and Material Projects

34. ICM funding requests must be based on discrete, material projects. As defined in the Board ACM report, "amounts must be based on discrete projects, and should be directly related to the claimed driver. The amount must be clearly outside of the base

[24] EB-2014-0219 Report of the OEB – New Policy Options for the Funding of Capital Investments: The Advanced Capital Module, September 18, 2014, p.15.
[25] EB-2020-0134, Exhibit B, Tab 1, Schedule 1, filed: 2020-09-03.
[26] As per the Board's EB-2017-0306/EB-2017-0307 Decision and Order, dated August 30, 2018, during Enbridge Gas' deferred rebasing term, the determination of utility results and earnings sharing amounts will use the annual OEB-approved return on equity. In accordance with the Board's 2019 Cost of Capital Parameters, the 2019 approved ROE was 8.98%.

upon which the rates were derived".[27] Also, as per the MAADs Decision, any individual project for which ICM funding is sought must have an in-service capital addition of at least $10 million.[28]

35. There are two Replacement projects and one Reinforcement project for which Enbridge Gas is seeking ICM funding, the St. Laurent NPS 12 Replacement Project in the EGD rate zone and the London Line Replacement Project and Sarnia Industrial Line Reinforcement Project in the Union South rate zone.

36. Each eligible capital project as identified for the EGD rate zone and Union rate zones is a discrete project that exceeds the materiality level of $10 million. These projects have been evaluated as part of the capital planning process, described in the AMP as discussed at Section 1. Each project is distinct, with significant influence on Enbridge Gas's operations as described in Table 8.

St. Laurent NPS 12 Replacement

37. This project is needed to replace approximately 13 km of steel gas distribution main in the city of Ottawa. The project will be completed in multiple phases over multiple years. The existing pipeline services over 165,000 customers in Ottawa, Ontario and Gatineau, Quebec and feeds 12 district regulating stations and one header station, including a large population of non-interruptible residential, industrial and commercial customers and a natural gas fired power plant. The project is required due to integrity issues with the existing pipeline and is necessary to maintain the safe and reliable delivery of natural gas to the Ottawa and Gatineau regions. The St. Laurent project consists of four phases. Phase 2 of the project was approved as part of the

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[27] EB-2014-0219 Report of the OEB – New Policy Options for the Funding of Capital Investments: The Advanced Capital Module, September 18, 2014, p.17.
[28] EB-2017-0306/EB-2017-0307, Decision and Order, August 30, 2018, pp.32-33.

Decision and Order in EB-2019-0006 and was placed into service in September, 2020. A Leave to Construct application is expected to be filed in December, 2020 for the remaining two phases of the project. For ICM eligibility purposes, each phase of the project has been evaluated individually based on the total in-service capital of that phase. In this application, Enbridge Gas is seeking ICM funding for Phase 3 of the project with a projected in-service date of December 2021. The Business Case for this project is filed in Table 8 below and will be updated after the Leave to Construct application has been filed with the OEB.

London Line Replacement Project

38. Enbridge Gas filed a Leave to Construct application with the OEB for the London Line Replacement Project on September 2, 2020 under docket number EB-2020-0192. This project is needed to replace the existing London Lines in their entirety. The existing London Lines are comprised of the London South Line and London Dominion Line which are two pipelines that are parallel to each other, approximately 60 km and 75 km in length, respectively. The proposed project involves replacing the existing London Lines with approximately 90.5 km of NPS 4 and NPS 6 dual fed pipeline from the Dawn Hub to Komoka Station with a maximum operating pressure of 3447 kPa. The proposed pipeline is necessary to replace the existing pipeline due to integrity concerns. Results from surveys and inspections conducted as part of the Enbridge Gas's Distribution Integrity Management Program ("DIMP") show that the existing London Lines are in poor condition and have several active degradation factors including loss of containment, shallow depth of cover and wall loss due to corrosion issues which could pose safety and security of supply concern if not addressed. The replacement of the London Lines as proposed is the most effective way of managing its ongoing safety and reliability. The Business Case for this project is filed in Table 8 below.

Sarnia Industrial Line Reinforcement

39. Enbridge Gas filed a Leave to Construct application with the OEB for the Sarnia Industrial Line Reinforcement on October 7, 2019 under docket number EB-2019-0218. The project is to install approximately 1.2 km of 6620 kPag MOP, NPS 20 pipeline and ancillary facilities from the Dow Valve site to the Bluewater Interconnect including tie-ins to the existing Sarnia Industrial Line ("SIL") system. The project is needed to supply the increased demand for reliable and safe delivery of natural gas and future growth in the Sarnia area, specifically to support a $2 billion expansion of Nova Chemicals existing Corunna site. The project is economically feasible and is in the best interest of the Ontario rate payers. In its Decision and Order dated March 12, 2020, the OEB finds that Enbridge Gas has demonstrated the need for this project and that the project is in the public interest. The Business Case for this project is filed in Table 8 below.

2.3 Prudence

40. The capital expenditures of the projects for which Enbridge Gas is seeking ICM funding approval for the EGD rate zone and Union rate zones are prudent and represent the most cost effective option for ratepayers.

41. The business case summaries in Table 8 below provide a description of each of the projects' need and prudence, with an overview of options considered.

Table 8

Business Case Summaries for ICM Projects by Rate Zone

EGD Rate Zone

St. Laurent NPS 12 Replacement	
Budget: $15.3 million Projected In-Service Date: December, 2021 In-Service Capital Spend: $13.0 million 2021 in-service $2.3 million 2022 in-service	Category of Investment: System Renewal Project Description and Drivers: • Replacement of approximately 13 km of steel gas distribution main with NPS 12 extra high pressure (XHP) pipeline. The existing pipeline serves over 165,000 customers in Ottawa, Ontario and Gatineau Quebec. The project is required due to integrity issues with the pipeline and will be completed in multiple phases over multiple years. • A Leave to Construct application was filed for Phase 2 of the project under docket EB-2019-0006 to replace approximately 1.7 km of pipeline on St. Laurent Boulevard between Montreal Road and Donald Street. The project was approved on September 26, 2019 and was placed into service on September 4, 2020. • All of the remaining phases of the project will be filed in the Leave to Construct application in December, 2020 and will be placed into service between 2021 and 2022. Only Phase 3 of the project is being requested as ICM as part of this Rate application. Phase 3 of the project includes replacement of approximately 9 kms of the pipeline along Lower Section, Montreal to Rockcliffe and Coventry/Cummings/St. Laurent.

	Other Options Considered: • Enbridge Gas will provide more details on the alternatives through an update to the ICM evidence after the Leave to Construct application is filed in December, 2020. The budget of $15.3 million covers all costs related to material, construction and labour, land costs, contingencies, overheads, and interest during construction.

Union Rate Zones

London Line Replacement	
Budget: $161.1 million Projected In-Service Date: December 2021 In-Service Capital Spend: $124.0 million 2021 in-service;	Category of Investment: System Renewal Project Description and Drivers: • Construction of 51.5 km NPS 4 and 39 km of NPS 6 dual fed pipeline operating at a maximum operating pressure of 3447 kPa. This 90.5 km replacement pipeline will run from Dawn Hub, 82.1 km east to Komoka Station in addition to adding a second feed comprising of 8.4 km NPS 6 from Strathroy Gate station. This proposed replacement will result in the abandonment of the existing London Lines, which are comprised of the 60 km London South Line and 75 km London Dominion Line. The Project is a replacement of the entirety of the existing London Lines. There are 148 services and 25 stations that will be upgraded and 9 new stations installed to facilitate the new proposed pipeline pressure.

$37.1 million 2022 in-service	• Analysis conducted by Enbridge Gas has shown that the existing London Lines are in poor condition and have several active degradation factors, including loss of containment, shallow depth of cover, and corrosion induced wall loss. Enbridge Gas has identified that the existing lines are an operational risk and should be replaced to manage the safety and reliability of the natural gas distribution in this area. • The budget covers all costs related to material, construction and labour, environmental projection measures, land acquisitions, contingencies, overheads and interest during construction. <u>Other Options Considered</u>: Enbridge Gas considered several alternatives during the development of a reinforcement or replacement plan including replacing the existing with a new pipeline operating at the same MOP, replacing the existing pipeline with a new pipeline operating at a different MOP, extending other distribution systems, obtaining supply from nearby non-Enbridge Gas pipelines and Demand Side Management. • *Replacing with a single fed, 1900 kPa pipeline from Dawn:* This design is based on replacement capacity and the same configuration of the existing systems by installing NPS 12 and 8 ST pipeline. However, this option would provide no reliability of supply for emergencies or operational outage. The option was deemed to be not viable due to the lack of operational flexibility and the higher costs associated with the design compared to the proposed project. • *Replacing with a dual fed, 1900 kPa Pipeline from Dawn and Strathroy :*

	Enbridge Gas reviewed the option of installing a combination of NPS 10/8/6 ST with feeds from Dawn and Strathroy. The feed from Strathroy would be a new 8.4 km 1900 kPa pipeline from Strathroy Gate Station which is served by the Dawn-Parkway system. This alternative reduced the required size of 51.5 km of the single fed design to NPS 6 as a result of the additional higher pressure feed. However, some NPS 10 pipe was still required due to the process of agricultural demand in the west section of the line. This option provides reliability of supply for emergency and operational requirements during summer temperatures but was unable to sustain expected loads from a single feed in shoulder months. The option is not deemed viable due to reduced operational flexibility and the increased cost when compared to the proposed project. • *Replace with a single fed 3447 kPa MOP Pipeline from Dawn*: This design is based on replacement capacity and the same configuration of the existing systems by installing NPS 10, 8 and 6 ST pipeline operating at 3447 kPa. However, this option would provide no reliability of supply for emergengies or operational outages. The option was deemed to be not viable due to the lack of operational flexibility and the higher costs associated with the design compared to the proposed project. • *Replace with a combination 1900 kPa and 420 kPa MOP system*: Under this design, 22 km of replacement pipe could be installed as NPS 6 PE and tied into existing 420 kPa MOP systems, with the remaining replacement pipe, approximately 60 km, as primarily NPS 8 ST, with some shorter sections of NPS 10 and 4 ST. Two 1900 kPa feeds from Dawn and Strathroy were required

	to maintain existing high pressure laterals served from the London Lines. The feed from Strathroy would be a new 8.4 km 1900 kPa pipeline from Strathroy Gate Station, which is served by the Dawn-Parkway pipeline. Although dual fed, this option provided no reliability of supply for the 1900 kPa systems as they are connected only by the lower pressure 420 kPa network. Any outages as a result of emergencies or operational constraints would result in the loss of all customers downstream of the isolation on the corresponding section of 1900 kPa pipeline. The option was deemed to be not viable due to the lack of operational flexibility the higher costs associated with the design compared to the proposed project. • *Obtaining Supply from nearby non-Enbridge Gas pipelines*: There are currently no nearby non-Enbridge Gas pipelines to leverage as an alternative supply to the London Line Replacement pipeline. Independent producers along this route are not large enough to support the Market, nor are they guaranteed as a source of supply; therefore, this alternative was not pursued further. • *Implementing Demand Side Management*: Enbridge Gas reviewed the alternative of implementing supplemental Demand Side Management ("DSM") for customers along the London Lines in order to defer, avoid or reduce the scale of this replacement project. If Enbridge Gas were to implement supplemental DSM, it would be possible to reduce demand along the lines; however, the demand could not be eliminated altogether. Because this project is being driven by integrity concerns of the existing pipelines, the need for

	replacement of the London Lines cannot be deferred or eliminated by implementing DSM. Enbridge Gas also looked at the option of implementing supplemental DSM to reduce the diameter of the pipeline. This option provides capacity to serve 2021 expected demand only while also providing reliability of supply for emergency and operational scenarios. The savings on pipeline size reduction would be exhausted by less than 2 years of supplemental DSM programming after which continued supplemental DSM spend or pipeline reinforcement would be required. Enbridge Gas filed a Leave to Construct application with the OEB for the London Line Replacement Project on September 2, 2020 under docket number EB-2020-0192. The budget of $161.1 million is updated from the EB-2020-0192 filing budget of $164.1 million. The variance between the the budget and the leave to contruct is due to a change in overhead allocations. The budget covers all costs related to material, construction and labour, land costs, contingencies, overheads, abandonment and interest during construction. Abandonment costs are excluded from 2021 in-service capital.

Sarnia Industrial Line Reinforcement	
Budget: $32.9 million Projected In-Service Date: Nov, 2021 In-Service Capital Spend: $31.5 million 2021 in-service; $1.4 million 2022 in-service	Category of Investment: System Access Project Description and Drivers: • Construction of approximately 1.2 kilometers of 6620 KPag, NPS 20 pipeline from the Dow Valve Site to the Bluewater Interconnect including tie-in to the existing SIL system and modifications to the existing Novacor Corunna Station. • The SIL system serves one of Enbridge Gas's most geographically concentrated in-franchise markets, consisting of one of the largest petrochemical and refined petroleum manufacturing areas in North America. The project will provide reliable, secure and economic solutions to serve the increased demand growth contracted with Nova Chemicals beginning in November 2021. The project will also address future growth in the Sarnia area. • The project enables enhanced in-line inspection capability by reducing pipeline velocities for appropriate speed control of inspection tool. • The budget covers all costs related to material, construction and labour, environmental protection measures, land acquisitions, contingencies, indirect overheads, and interest during construction. • Economic analysis has been completed in accordance with E.B.O. 188. The project is economically justified and is in the public interest.

	<u>Other Options Considered</u>:
	• Enbridge Gas reviewed several facility and non-facility options when considering alternatives for the Sarnia Industrial Line:
	    o New Pipeline from Bluewater interconnect to the Churchill Road Station and Sarnia Industrial Station: Construction of 24 km of 6620 KPag MOP pipeline facilities to loop the existing NPS 12 SIL and NPS 10 Dow pipeline
	    o New Pipeline from Great Lakes Courtright to Courtright Line: Construction of 4.5 km of 6620 kPag MOP pipeline facilities to loop the existing SIL
	    o New Pipeline from the Dawn Hub to the Payne Pool Station: Construction of 21 km of 6895 kPag MOP pipeline facilities to provide a large volume direct connection to Dawn
	• Enbridge Gas investigated the options of replacing existing pipelines:
	    o Replace the NPS 10 Dow pipeline between the Bluewater Interconnect and Churchill Road Station
	    o Replace NPS 12 SIL between Bluewater Interconnect and Sarnia Industrial Station
	• The option of installing a new compressor plant
	• The option of installing a new Liquefied Natural Gas (“LNG”)
	• The option of installing a new Compressed Natural Gas facility
	• The option of firm gas supply delivered at the Bluewater Interconnect Station
	• Integrated Resource Planning

	The Sarnia Industrial Line Reinforcement project was subject to a Leave to Construct application in EB-2019-0218. In this application, Enbridge Gas presented the need for the project, the alternatives considered for the project, the project cost and economics, environmental issues, land matters and indigenous consultation. In its Decision and Order dated March 12, 2020, the OEB found that: • Enbridge Gas demonstrated the need for this project • Enbridge Gas considered a reasonable range of alternatives and found that the proposed project is superior to these alternatives • The project is in the public interest and is the lowest cost alternative. The OEB also found that Enbridge Gas has adequately addressed environmental issues, land matters and the procedural aspects of the duty to consult with impacted Indigenous communities. The budget of $32.9 million is updated from the EB-2019-0218 filing budget of $30.8 million. The variance between the the budget and the leave to contruct is due to a change in overhead allocations. The budget covers all costs related to material, construction and labour, land costs, contingencies, overheads, and interest during construction.

3. CUSTOMER CONSULTATION

42. Enbridge Gas commissioned Ipsos Public Affairs to conduct a customer engagement survey to provide insight into the satisfaction, needs and preferences of Enbridge

Gas customers on future investment plans. The results demonstrate that customers value the safe, reliable, cost-effective, and environmentally responsible provision of natural gas. Enbridge Gas's customers believe investments should be made in maintaining existing reliability and in safety. Customers want a plan that will keep the system healthy and reliable in the long run, while also ensuring a demonstration of prudence in spending decisions. This feedback is considered in how Enbridge Gas plans, manages and develops assets within each of the rate zones. The projects for which Enbridge Gas is seeking ICM funding address integrity issues, provide for more robust supplies to the system and allow additional customer load to access the system.

4. CALCULATION OF REVENUE REQUIREMENT

43. Table 9 provides the incremental revenue requirement Enbridge Gas is seeking as ICM funding for 2021 ICM projects. The total capital cost of the 2021 ICM funding request is $165.8 million with an associated total revenue requirement of $24.7 million from 2021 to 2023 and an average annual revenue requirement of $8.2 million. The incremental revenue requirement includes costs associated with the capital investment (return on rate base, depreciation expense and associated income taxes) only.

Table 9

Total Incremental Revenue Requirement by Rate Zone

Line No.	Particulars ($000's)	2021	2022	2023	Total	Average Annual
		(a)	(b)	(c)	(d)	(e) = (d)/3
	EGD Rate Zone					
1	St. Laurent NPS 12 Replacement	(703)	1,068	1,063	1,428	476
	Union South Rate Zone					
2	London Line Replacement	(6,408)	12,966	12,799	19,357	6,453
3	Sarnia Industrial Line Reinforcement	(1,482)	2,707	2,697	3,922	1,307
4	Total Incremental Revenue Requirement	(8,593)	16,471	16,559	24,707	8,236

44. The detailed incremental revenue requirement for each of the 2021 ICM projects for the deferred rebasing period is filed as Appendix E in this exhibit.

45. The return on rate base is calculated using the cost of capital parameters approved by the Board in EGD’s 2018 Rate Adjustment Application (EB 2017-0086) for the EGD rate zone and in Union’s 2013 Cost of Service application (EB 2011-0210) for the Union rate zones.

46. Depreciation expense is calculated using Board-approved depreciation rates beginning the month following the in-service date of the project in accordance with the accounting policies of Enbridge Gas in 2021.

47. Incremental income taxes as a result of the projects are calculated using the current tax rates. Income taxes include taxes on the equity and preference share return on rate base as well as the utility timing differences associated with the difference between utility income and taxable income, and reflect 100% of the impacts of the accelerated Capital Cost Allowance.[29] Income taxes are grossed up to account for the impact the additional revenue will have on income tax expense.

48. The 2022 in-service capital forecast of the 2021 ICM Projects will be included in the in-service capital for purposes of determining the maximum eligible incremental capital in 2022.

5. COST ALLOCATION

49. Enbridge Gas is proposing to allocate the ICM Project revenue requirement to rate classes based on the most recently approved cost allocation methodology updated for the current year forecast.

50. Enbridge Gas proposes to allocate the annual average net revenue requirement with respect to the St. Laurent NPS 12 Replacement project among different rate classes in EGD rate zone according to the most recent Board approved cost allocation methodology (EB-2017-0086) for the low pressure mains . The allocator can be found at EB-2017-0086, Exhibit G2, Tab 6, Schedule 3, Page 2, Item 2.4 (Delivery Demand LP allocator).

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[29] On June 21, 2019, Bill C-97, the Budget Implementation Act, 2019, No.1, was given Royal Assent. Bill C-97 includes an “Accelerated Investment Incentive” program which provides for a first-year increase in Capital Cost Allowance (“CCA”) deductions on eligible capital assets acquired after November 20, 2018 (“Accelerated CCA”).

51. Enbridge Gas proposes to allocate the annual average net revenue requirement with respect to the London Line Replacement Project to Union South rate classes in proportion to the forecast Union South in-franchise design day demands of firm and interruptible customers served by the distribution system excluding customers served directly off transmission lines. This proposed cost allocation methodology is consistent with the allocation of Union South Distribution Demand costs most recently approved by the Board in EB-2011-0210 (Union's 2013 approved cost allocation study). The assets installed with the London Line Replacement Project will be categorized as distribution consistent with the design of the pipeline as described in the EB-2020-0192 (London Line Replacement Project) evidence. The allocation of Distribution Demand costs recognizes distribution lines are designed to meet Union South in-franchise distribution demands on design day.

52. Enbridge Gas proposes to allocate the annual average net revenue requirement with respect to the Sarnia Industrial Line Reinforcement Project to Union South rate classes in proportion to the forecast Union South in-franchise design day demands. This proposed cost allocation methodology is consistent with the allocation of Other Transmission Demand costs approved by the Board in EB-2011-0210 (Union's 2013 approved cost allocation study). The assets installed with the Sarnia Industrial Line Reinforcement project will be categorized as Other Transmission assets. The allocation of Other Transmission costs recognizes other transmission lines are designed to meet Union South in-franchise demands on design day.

53. The cost allocation factors and the allocation of project revenue requirement to the rate classes for each of the 2021 ICM projects are filed as Appendix F in this exhibit.

6. ICM UNIT RATES

54. Enbridge Gas is seeking approval of ICM unit rates beginning in 2021 for the duration of the deferred rebasing period to recover the total revenue requirement of the 2021 ICM projects from 2021 to 2023 as part of this proceeding. To calculate the ICM unit rates, Enbridge Gas used the allocated average annual revenue requirement and the forecast 2021 billing units for each respective rate class. Consistent with the treatment of 2019 and 2020 approved ICM project unit rates, Enbridge Gas proposes to embed the ICM unit rates in the delivery and transportation charges on the applicable rate schedule and customer bill. The derivation of the ICM unit rates for 2021 ICM projects is filed as Appendix G in this exhibit.

55. The ICM unit rates presented in Appendix G were prepared assuming an implementation date in rates of January 1, 2021. Following the Board's Decision in this proceeding, Enbridge Gas will file a draft rate order including updated ICM unit rates to reflect recovery of the total revenue requirement of the projects for the deferred rebasing period beginning with the implementation date if different than January 1, 2021.

7. ICM BILL IMPACTS

56. The bill impact associated with the 2021 ICM funding request for a typical Rate 1 residential customer consuming 2,400 m^3 annually in the EGD rate zone is an increase of $0.11.

57. The bill impact associated with the 2021 ICM funding request for a typical Rate M1 residential customer consuming 2,200 m^3 annually in the Union South rate zone is an increase of $2.71.

58. There is no bill impact associated with the 2021 ICM funding request for a typical Rate 01 residential customer in the Union North rate zone as there is no ICM project applicable to this rate zone.

59. The ICM bill impacts by rate class are filed as Appendix H for the EGD rate zone and Appendix I for the Union rate zones.

Table A

General Plant Capital Expenditures[1] by category (2016-2025) – EGD Rate Zone ($ Millions)

Line No.	Category	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Fcast	2021 Budget	2022 Budget	2023 Budget	2024 Budget	2025 Budget
1	Equipment & Materials	-	2.4	2.1	0.1	2.7	3.8	3.9	4.2	4.1	4.3
2	Furniture/Structures & Improvements	22.1	9.4	8.7	33.6	35.1	56.5	10.0	67.7	16.1	23.7
3	IT Implementation	18.6	27.7	32.7	32.7	14.6	28.3	39.4	30.8	27.3	23.8
4	Land – Storage	-	-	-	-	-	0.3	0.2	1.5	0.1	0.1
5	Leasehold Improvements	-	-	-	-	-	-	-	-	-	-
6	Structures and Improvement - Storage	3.9	-	0.2	0.2	0.2	-	-	-	-	-
7	Tools	0.7	-	1.3	1.3	1.1	1.1	1.1	1.2	1.2	1.2
8	Vehicles	1.7	6.6	2.3	2.3	7.3	5.9	6.1	6.4	6.4	6.6
9	WAMS	35.7	2.0	-	-	-	-	-	-	-	-
10	**General Plant - EGD Rate Zone**	**82.6**	**48.1**	**47.3**	**70.4**	**61.0**	**95.9**	**60.7**	**111.8**	**55.2**	**59.7**

[1] Overheads are included in project costs in years 2021-2025

Table B

General Plant Capital Expenditures[2] by category (2016-2025) – Union Rate Zones ($ Millions)

Line No.	Category	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Fcast	2021 Budget	2022 Budget	2023 Budget	2024 Budget	2025 Budget
1	Tools	2.4	2.7	2.0	1.5	1.9	1.9	2.0	2.1	2.1	2.2
2	Equipment & Materials	-	-	-	-	-	3.7	3.8	4.1	4.1	4.2
2	LNG Capital Maintenance	0.1	0.2	-	-	-	-	-	-	-	-
3	Measurement Electronics Upgrades	-	0.1	0.8	-	-	-	-	-	-	-
4	Compressor and Dehy Capital Maintenance	-	-	1.4	-	-	-	-	-	-	-
5	Fleet Vehicles	3.1	6.2	7.7	12.4	7.0	6.1	6.2	6.6	6.6	6.8
6	Land – Storage, Transmission & LNG	0.2	0.3	-	-	0.5	1.7	1.1	0.6	0.8	0.5
7	Leasehold Improvements	8.7	9.1	12.3	7.7	6.2	30.9	25.5	51.2	21.4	46.2
8	Other - Indirect Materials	0.2	0.3	-	0.2	0.2	-	-	-	-	-
9	Service Facilities - Dawn	6.1	1.5	-	-	-	-	-	-	-	-
10	IT Implementation	23.9	22.4	23.8	30.0	12.6	11.3	18.2	14.2	37.4	31.2
11	**General Plant - Union Rate Zones**	**44.8**	**42.8**	**48.0**	**51.8**	**28.4**	**55.6**	**56.8**	**78.8**	**72.4**	**91.1**

[2] Overheads are included in project costs in years 2021-2025

Table C

System Access Capital Expenditures[3] by category (2016-2025) – EGD Rate Zone ($ Millions)

Line No.	Category	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Fcast	2021 Budget	2022 Budget	2023 Budget	2024 Budget	2025 Budget
1	Commercial	26.0	19.5	19.8	25.5	16.5	24.7	24.5	25.7	24.6	24.6
2	Industrial	3.7	3.9	(1.9)	0.3	0.3	4.9	4.9	5.1	4.8	4.8
3	Meters - Capital Purchase Program (Growth)	3.4	6.7	5.1	12.1	7.0	9.5	9.5	10.1	9.4	9.4
4	NGV	6.4	2.1	7.2	1.3	0.9	1.1	1.0	0.9	0.9	0.9
5	Hydrogen Blending	-	-	-	-	0.6	2.7	-	-	-	-
6	Storage Growth	-	-	-	-	-	-	-	50.9	1.6	-
7	Rebillable Relocations	9.8	3.5	(2.7)	46.1	0.7	10.4	11.8	12.4	12.1	12.1
8	Residential	66.2	70.8	81.4	65.6	100.6	114.3	112.9	118.6	114.2	113.9
9	Sales Stations - New	2.8	2.8	-	0.2	0.1	-	-	-	-	-
10	**System Access - EGD Rate Zone**	**118.3**	**109.3**	**108.9**	**151.1**	**126.9**	**167.6**	**164.6**	**223.7**	**167.6**	**165.7**

Table D

System Access Capital Expenditures[4] by category (2016-2025) – Union Rate Zones ($ Millions)

Line No.	Category	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Fcast	2021 Budget	2022 Budget	2023 Budget	2024 Budget	2025 Budget
1	CNG	-	-	-	-	-	0.9	0.9	1.0	-	-
2	Transmission Growth	-	-	-	-	-	32.1	216.5	6.4	134.7	5.0
3	Meters – Capital Purchase Program (Growth)	-	-	-	-	6.9	8.8	9.1	9.9	10.0	10.4
4	General Customer Growth	85.4	70.0	66.7	85.2	66.9	76.4	72.8	78.2	77.9	79.9
5	Municipal Replacement	20.2	26.2	16.8	19.2	24.0	32.5	29.2	30.8	30.2	30.4
6	**System Access - Union Rate Zones**	**105.6**	**96.2**	**83.5**	**104.4**	**97.8**	**150.7**	**328.5**	**126.3**	**252.8**	**125.7**

[3] Overheads are included in project costs in years 2021-2025
[4] Overheads are included in project costs in years 2021-2025

Table E

System Renewal Capital Expenditures[5] by category (2016-2025) – EGD Rate Zone ($ Millions)

Line No.	**Category**	**2016 Actual**	**2017 Actual**	**2018 Actual**	**2019 Actual**	**2020 Fcast**	**2021 Budget**	**2022 Budget**	**2023 Budget**	**2024 Budget**	**2025 Budget**
1	Compressor Equipment - Storage	5.6	9.7	6.9	0.2	29.4	49.4	42.0	15.3	235.8	45.8
2	Corrosion Prevention	0.5	1.3	1.9	3.2	1.3	3.1	3.1	3.2	2.2	2.3
3	Field Lines - Storage	1.5	0.5	0.3	-	-	-	-	-	-	-
4	Gate & Feeder Stations	7.6	5.2	6.2	1.4	24.5	29.8	14.9	28.8	20.3	18.0
5	Inside Regulator Program	6.6	3.1	0.8	0.1	2.4	0.6	0.6	0.6	0.6	0.6
6	Integrity Digs	2.2	1.9	(0.6)	1.2	-	-	-	-	-	-
7	Integrity Retrofit	5.1	0.9	1.1	0.4	-	-	-	-	-	-
8	Main Replacement	18.9	16.1	19.9	13.0	35.8	69.4	222.4	55.2	77.4	79.6
9	Transmission Pipe – Improvements & Replacements	-	-	-	-	10.4	6.5	8.6	5.6	10.6	2.9
10	Meters - Capital Purchase Program (Maintenance)	7.9	15.7	11.8	28.2	6.8	24.2	23.0	23.4	29.7	22.4
11	Non-Rebillable Relocations	-	-	1.3	2.5	-	-	-	-	-	-
12	Regulator Refit	17.5	12.3	14.0	29.2	17.0	21.8	22.2	23.9	23.8	23.9
13	Remediation - Customer Assets	-	1.0	1.0	2.0	2.9	1.2	0.8	0.9	0.8	1.1
14	Service Relay	20.7	21.6	19.7	22.4	17.2	37.9	38.3	43.7	46.4	56.0
15	Station Rebuilds	11.9	9.9	6.5	5.9	14.1	15.9	27.8	15.2	13.9	15.7
16	Wells and Well Equipment - Storage	3.1	3.0	1.5	0.7	-	-	-	-	-	-
17	**System Renewal - EGD Rate Zone**	**109.1**	**102.2**	**92.3**	**110.4**	**161.8**	**259.8**	**403.7**	**215.8**	**461.5**	**268.3**

[5] Overheads are included in project costs in years 2021-2025

Table F

System Renewal Capital Expenditures[6] by category (2016-2025) – Union Rate Zones ($ Millions)

Line No.	Category	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Fcast	2021 Budget	2022 Budget	2023 Budget	2024 Budget	2025 Budget
1	Bare and Unprotected steel	-	-	-	3.7	-	-	-	-	-	-
2	Corrosion Prevention	6.2	7.2	5.9	7.0	5.1	10.0	12.4	9.2	9.0	8.7
3	Compression Equipment - Storage	0.9	0.9	0.1	1.0	6.1	5.9	6.8	14.6	181.9	7.4
4	Compressor Overhauls	4.7	0.6	-	-	-	0.3	4.5	3.6	0.2	2.8
5	Excess Flow Valves	-	0.2	-	-	-	-	-	-	-	-
6	Transmission Equipment - Storage	-	-	-	-	8.2	14.6	13.3	42.5	14.1	10.7
7	Main Replacement	30.5	32.4	45.1	33.7	106.6	197.2	66.6	45.6	70.7	37.1
8	Service Relay	-	-	-	-	6.2	7.3	7.4	7.9	7.9	8.1
9	Leakage	-	-	-	2.9	-	-	-	-	-	-
10	LNG Capital Maintenance	1.0	1.9	0.1	-	0.7	-	-	16.0	-	-
11	Measurement Electronics Upgrades	1.6	2.0	0.3	0.9	-	-	-	-	-	-
12	Meter Exchange Program	30.8	29.4	32.7	43.4	16.7	28.3	29.1	31.7	32.1	33.4
13	Regulator Refit	-	-	-	-	12.1	18.0	17.9	19.3	18.9	19.1
14	Station Rebuilds	-	-	-	-	8.1	22.8	16.4	14.9	8.6	6.6
15	Gate & Feeder Stations	-	-	-	-	21.5	23.2	23.4	5.0	2.5	2.5
16	Service Replacement	4.7	4.6	5.0	3.2	-	-	-	-	-	-
17	Station Painting	-	0.2	1.8	2.1	-	-	-	-	-	-
18	Stations Capital Maintenance	4.5	10.9	8.4	6.3	-	-	-	-	-	-
19	General Pipeline Maintenance	5.2	3.8	-	2.2	-	-	-	-	-	-
20	**System Renewal - Union Rate Zones**	**90.1**	**94.1**	**99.4**	**106.4**	**191.3**	**327.6**	**197.6**	**210.3**	**345.9**	**136.4**

[6] Overheads are included in project costs in years 2021-2025

Table G

System Service Capital Expenditures[7] by category (2016-2025) – EGD Rate Zone ($ Millions)

Line No.	Category	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Fcast	2021 Budget	2022 Budget	2023 Budget	2024 Budget	2025 Budget
1	Carbon Capture	-	-	-	-	-	-	-	-	-	-
2	Integrity Initiatives	1.8	4.7	6.7	7.1	15.1	31.2	21.7	6.7	19.7	8.9
3	MOP	0.8	1.4	1.4	0.2	-	-	-	-	-	-
4	Records Integrity	1.8	4.6	4.9	9.5	-	-	-	-	-	-
5	System Reinforcement	7.9	4.7	9.9	7.1	10.8	19.3	10.5	21.3	19.7	79.7
6	GTA	114.8	4.8	-	-	-	-	-	-	-	-
7	**System Service - EGD Rate Zone**	**127.1**	**20.2**	**22.9**	**23.9**	**25.9**	**50.5**	**32.2**	**28.0**	**39.4**	**88.7**

[7] Overheads are included in project costs in years 2021-2025

Table H

System Service Capital Expenditures[8] by category (2016-2025) – Union Rate Zones ($ Millions)

Line No.	Category	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Fcast	2021 Budget	2022 Budget	2023 Budget	2024 Budget	2025 Budget
1	Excess Flow Valves	1.3	0.7	-	-	-	-	-	-	-	-
2	General Mains	0.1	-	-	-	-	-	-	-	-	-
3	Integrity Initiatives	14.6	23.3	22.7	37.7	39.3	52.4	76.9	44.5	41.3	44.3
4	LNG Capital Maintenance	-	0.1	-	-	-	0.3	-	-	-	-
5	Measurement Electronics Upgrades	-	-	-	0.1	-	-	-	-	-	-
6	Measurement Upgrade	0.1	-	-	-	-	-	-	-	-	-
7	Distribution Reinforcement	16.1	9.3	16.5	18.2	-	-	-	-	-	-
8	Emissions Action Plan	2.3	4.1	-	0.1	-	-	-	-	-	-
9	Monitoring Systems	-	-	-	-	-	0.2	0.1	0.0	0.0	0.0
10	Odourant Upgrades	0.8	0.7	0.6	1.0	-	-	-	-	-	-
11	Station Reinforcement	0.7	-	0.1	0.7	-	-	-	-	-	-
12	Storage Improvements	0.6	1.1	2.0	0.6	-	-	-	-	-	-
13	System Growth	683.5	366.4	159.3	81.5	-	-	-	-	-	-
14	System Reinforcement	-	-	-	-	66.9	40.2	46.0	132.5	11.2	123.9
15	Transmission Reinforcement	0.4	-	-	22.2	-	-	-	-	-	-
16	Integrated Resource Planning	-	0.1	-	-	-	-	-	-	-	-
17	**System Service - Union Rate Zones**	**720.5**	**405.8**	**201.2**	**162.1**	**106.2**	**93.1**	**123.0**	**177.0**	**52.5**	**168.2**

[8] Overheads are included in project costs in years 2021-2025

EGD RATE ZONE
Calculation of 2019 and 2018 Revenue at 2018 Approved Rates

				2018		2019	
Line No.	Particulars	Billing Units	Rates (cents / m^3)	Approved Usage	Revenue ($000's)	Actual Usage	Revenue ($000's)
		(a)	(b)	(c)	(d)	(e)	(f)
	Rate 1 General Service						
1	Customer Charge	bills	$ 20.00	24,180,918	483,618	24,555,584	491,112
2	Delivery Charge		6.7333	4,751,509	319,931	4,825,130	324,888
3	Load Balancing	10^3 m^3	0.3411	4,750,232	16,203	4,823,834	16,454
4	Transportation	10^3 m^3	0.0235	4,634,556	1,089	4,706,365	1,106
5	Transportation Dawn	10^3 m^3	0.0078	82,881	6	84,165	7
6	Gas Supply Commodity - System	10^3 m^3	0.0780	4,583,611	3,575	4,654,631	3,631
7	Total Rate 1				824,423		837,197
	Rate 6 General Service						
8	Monthly Charge	bills	$ 70.00	2,010,770	140,754	2,016,776	141,174
9	Delivery Charge		3.7157	4,801,738	178,416	4,816,081	178,949
10	Load Balancing	10^3 m^3	0.3202	4,829,758	15,465	4,844,183.75	15,511
11	Transportation	10^3 m^3	0.0235	3,620,680	851	3,631,494.80	853
12	Transportation Dawn	10^3 m^3	0.0078	895,132	70	897,805.27	70
13	Gas Supply Commodity - System	10^3 m^3	0.0993	3,121,315	3,099	3,130,637.74	3,109
14	Total Rate 6				338,655		339,666
	Rate 9 Contract Service						
15	Monthly Charge	bills	$ 235.95	-	-	-	-
	Delivery Charge						
16	First 20,000 m^3	10^3 m^3	11.2489	-	-	-	-
17	Over 20,000 m^3	10^3 m^3	10.5292	-	-	-	-
18	Load Balancing	10^3 m^3	0.0196	-	-	-	-
19	Transportation	10^3 m^3	0.0235	-	-	-	-
20	Transportation Dawn	10^3 m^3	0.0078				
21	Gas Supply Commodity - System	10^3 m^3	0.0431	-	-	-	-
22	Total Rate 9				-		-

EGD RATE ZONE
Calculation of 2019 and 2018 Revenue at 2018 Approved Rates

Line No.	Particulars	Billing Units	Rates (cents / m^3)	2018 Approved Usage	2018 Revenue ($000's)	2019 Actual Usage	2019 Revenue ($000's)
		(a)	(b)	(c)	(d)	(e)	(f)
	Rate 100 Contract Service						
1	Monthly Charge	bills	$ 122.01	-	-	50	6
2	Contract Demand	10^3 m^3	36.00	-	-	3,420	1,231
3	Load Balancing	10^3 m^3	0.3202	-	-	14,634	47
4	Transportation	10^3 m^3	0.0236	-	-	12,099	3
5	Transportation Dawn	10^3 m^3	0.0078	-	-	2,159	0
6	Gas Supply Commodity - System	10^3 m^3	0.0993	-	-	12,099	12
7	Total Rate 100				-		1,299
	Rate 110 Contract Service						
8	Monthly Charge	bills	$ 587.37	3,180	1,868	3359	1,973
9	Contract Demand	10^3 m^3	22.91	48,218	11,047	72,138	16,527
	Delivery Charge		-				
10	First 1,000,000 m^3	10^3 m^3	0.5671	639,885	3,629	695,236	3,943
11	Over 1,000,000 m^3	10^3 m^3	0.4171	149,151	622	166,781	696
12	Load Balancing	10^3 m^3	0.0713	789,036	563	862,017	615
13	Transportation	10^3 m^3	0.0235	216,486	51	78,083	18
14	Transportation Dawn	10^3 m^3	0.0078	474,890	37	752,744	59
15	Gas Supply Commodity - System	10^3 m^3	0.0433	56,322	24	66,868	29
16	Total Rate 110				17,840		23,859
	Rate 115 Contract Service						
17	Monthly Charge	bills	$ 622.62	324	202	268	167
18	Contract Demand	10^3 m^3	24.36	20,166	4,912	20,134	4,905
	Delivery Charge						
19	First 1,000,000 m^3	10^3 m^3	0.2227	170,833	380	155,555	346
20	Over 1,000,000 m^3	10^3 m^3	0.1228	371,998	457	292,050	359
21	Load Balancing	10^3 m^3	0.0253	542,831	137	447,605	113
22	Transportation	10^3 m^3	0.0236	11,292	3	741	0
23	Transportation Dawn	10^3 m^3	0.0078	362,012	28	258,802	20
24	Gas Supply Commodity - System	10^3 m^3	0.0433	-	-	741	0
25	Total Rate 115				6,120		5,911
	Rate 125 Contract Service						
26	Monthly Charge	bills	$ 500.00	48	24	48	24
27	Contract Demand	10^3 m^3	10.0427	111,124	11,160	113,305	11,379
28	Total Rate 125				11,184		11,403

EGD RATE ZONE
Calculation of 2019 and 2018 Revenue at 2018 Approved Rates

				2018		2019	
Line No.	Particulars	Billing Units	Rates (cents / m^3)	Approved Usage	Revenue ($000's)	Actual Usage	Revenue ($000's)
		(a)	(b)	(c)	(d)	(e)	(f)
	Rate 135 Contract Service						
	Winter (December to March)						
1	Monthly Charge	bills	$ 115.08	172	19.79	151	17
	Delivery Charge						
2	First 14,000 m^3	10^3 m^3	7.0437	664	46.79	1,202	85
3	Next 28,000 m^3	10^3 m^3	5.8445	1,026	59.98	2,072	121
4	Over 42,000 m^3	10^3 m^3	5.4446	2,010	109.44	7,578	413
	Rate 135 Contract Service						
	Summer (April to November)						
	Monthly Charge	bills	$ 115.08	344	40	340	39
	Delivery Charge						
5	First 14,000 m^3	10^3 m^3	2.3073	4,514	104.15	3,811	88
6	Next 28,000 m^3	10^3 m^3	1.6073	8,724	140.23	7,228	116
7	Over 42,000 m^3	10^3 m^3	1.4074	47,562	669.39	41,041	578
8	Load Balancing	10^3 m^3	-	64,501	-	62,933	-
9	Transportation	10^3 m^3	0.0235	18,862	4.43	7,698	2
10	Transportation Dawn	10^3 m^3	0.0078	39,641	3.09	55,235	4
11	Gas Supply Commodity - System	10^3 m^3	0.0503	4,473	2.25	1,598	1
12	Total Rate 135				1,199		1,464
	Rate 145 Contract Service						
13	Monthly Charge	bills	$ 123.34	432	53	304	37
14	Contract Demand	10^3 m^3	8.23	9,242	761	10,036	826
	Delivery Charge						
15	First 14,000 m^3	10^3 m^3	2.6095	5,143	134	3,057	80
16	Next 28,000 m^3	10^3 m^3	1.2507	9,200	115	5,371	67
17	Over 42,000 m^3	10^3 m^3	0.6916	35,793	248	21,835	151
18	Load Balancing	10^3 m^3	0.1599	50,136	80	30,263	48
19	Transportation	10^3 m^3	0.0236	10,692	3	1,626	0
20	Transportation Dawn	10^3 m^3	0.0078	25,167	2	28,638	2
21	Gas Supply Commodity - System	10^3 m^3	0.0469	8,575	4	1,626	1
22	Total Rate 145				1,399		1,213

EGD RATE ZONE
Calculation of 2019 and 2018 Revenue at 2018 Approved Rates

Line No.	Particulars	Billing Units	Rates (cents / m³)	2018 Approved Usage	2018 Revenue ($000's)	2019 Actual Usage	2019 Revenue ($000's)
		(a)	(b)	(c)	(d)	(e)	(f)
	Rate 170 Contract Service						
1	Monthly Charge	bills	$ 279.31	300	84	276	77
2	Contract Demand	10^3 m^3	4.0900	32,846	1,343	33,150	1,356
	Delivery Charge						
3	First 1,000,000 m^3	10^3 m^3	0.2793	193,825	541	187,024	522
4	Over 1,000,000 m^3	10^3 m^3	0.0793	97,328	77	98,085	78
5	Load Balancing	10^3 m^3	0.0699	291,152	204	285,109	199
6	Transportation	10^3 m^3	0.0235	42,446	10	18,233	4
7	Transportation Dawn	10^3 m^3	0.0078	171,438	13	127,658	10
8	Gas Supply Commodity - System	10^3 m^3	0.0432	34,475	15	18,233	8
9	Total Rate 170				2,287		2,254
	Rate 200 Contract Service						
10	Monthly Charge	bills		12	-	12	-
11	Contract Demand	10^3 m^3	14.7000	14,801	2,176	14,829	2,180
	Delivery Charge						
12	Per cubic metre of gas delivered	10^3 m^3	- 0.0208	169,764	(35)	196,879	(41)
13	Load Balancing	10^3 m^3	0.3097	169,764	526	196,879	610
14	Transportation	10^3 m^3	0.0235	129,627	30		-
15	Transportation Dawn	10^3 m^3	0.0078	40,137	3	43,857	3
16	Gas Supply Commodity - System	10^3 m^3	0.0432	129,627	56	153,022	66
17	Gas Supply Commodity - Buy/Sell	10^3 m^3	0.0237	-	-	-	-
18	Total Rate 200				2,756		2,818
	Rate 300 Contract Service						
19	Monthly Charge	bills	$ 500.00	12	6	12	6
20	Contract Demand	10^3 m^3	27.4365	187	51	187	51
21	Total Rate 300				57		57
	Rate 332 Transportation Service						
22	Monthly Contract Demand	$/GJ	1.2075	1,200,000	17,388	1,200,000	17,388
23	Total Rate 332				17,388		17,388
	Rate 325 Storage and Transmission						
24	Monthly Charge	bills	$ 1.00	1	1,800	150	1,800
25	Total Rate 325				1,800		1,800
26	Grand Total				1,225,109		1,246,330

UNION RATE ZONES
Calculation of 2019 and 2013 Revenue at 2013 Approved Rates

				2013		2019	
Line No.	Particulars	Billing Units	Rates (cents / m^3)	Approved Usage	Revenue ($000's)	Actual Usage	Revenue ($000's)
		(a)	(b)	(c)	(d)	(e)	(f)
	Rate 01						
1	Monthly Charge	bills	$ 21.00	3,839,732	80,634	4,243,720	89,118
2	Delivery Charge	10^3m^3	8.9074	884,421	78,779	977,474	87,068
3	Transportation	10^3m^3	0.01169	884,421	103	977,474	114
4	Storage	10^3m^3	1.7032	884,421	15,063	977,474	16,648
5	Total Rate 01				174,580		192,948
	Rate 10						
6	Monthly Charge	bills	$ 70.00	24,629	1,724	25,731	1,801
7	Delivery Charge	10^3m^3	5.5035	322,887	17,770	337,334	18,565
8	Transportation	10^3m^3	0.0048	322,887	15	337,334	16
9	Storage	10^3m^3	1.2478	322,887	4,029	337,334	4,209
10	Total Rate 10				23,539		24,592
	Rate 20						
11	Monthly Charge	bills	$ 1,000.00	748	748	691	691
	Monthly Demand Charge						
12	First 70,000 m^3	10^3m^3/d	27.8179	23,260	6,470	21,971	6,112
13	All over 70,000 m^3	10^3m^3/d	16.3583	19,701	3,223	63,984	10,467
	Commodity Charge						
14	First 852,000 m^3	10^3m^3	0.5135	331,197	1,701	293,091	1,505
15	All over 852,000 m^3	10^3m^3	0.3757	298,605	1,122	229,697	863
16	Transportation Account Charge	10^3m^3	$ 219.43	460	101	398	87
		10^3m^3					
17	Gas Supply Demand Charge	10^3m^3	1.6293	6,873	112	7,494	139
	Fort Frances		0.2175	-	-	-	-
	Western		0.0075	2,650	20	1,332	10
	Northern		0.0182	702	13	2,356	43
	Eastern		0.0226	3,521	79	3,806	86
	Storage (GJ's)						
18	Demand	GJ/d	9.6425	99,288	957	141,504	1,364
19	Commodity	GJ	0.1558	639,477	100	681,011	106
20	Total Rate 20				14,534		21,334.14
	Rate 25						
21	Monthly Charge	bills	$ 375.00	842	316	819	307
22	Delivery Charge	10^3m^3	2.6004	159,555	4,149	119,200	3,100
23	Transportation Account Charge	bills	$ 219.43	36	8	172	38
24	Gas Supply Transportation	10^3m^3	0.0516	42,913	22	35,972	19
25	Total Rate 25				4,495		3,463
	Rate 100						
26	Monthly Charge	bills	$ 1,500.00	226	339	151	227
27	Demand	10^3m^3/d	15.3415	71,975	11,042	43,713	6,706
28	Commodity	10^3m^3	0.2132	1,895,488	4,042	1,020,510	2,176
29	Transportation Account Charge	bills	$ 219.43	226	50	145	32
	Storage (GJ's)						
30	Demand	GJ/d	5.5595	15,600	87	-	-
31	Commodity	GJ	0.1558	100,000	16	-	-
32	Total Rate 100				15,575		9,141
33	Total Union North In-franchise				232,722		251,478

UNION RATE ZONES
Calculation of 2019 and 2013 Revenue at 2013 Approved Rates

				2013		2019	
Line No.	Particulars	Billing Units	Rates (cents / m^3)	Approved Usage	Revenue ($000's)	Actual Usage	Revenue ($000's)
		(a)	(b)	(c)	(d)	(e)	(f)
	Rate M1						
1	Monthly Charge	bills	$ 21.00	12,706,802	266,843	13,695,351	287,602
2	Delivery Commodity Charge (avg rate)	10^3m^3	3.4245	2,939,543	100,664	3,168,231	108,495
3	Storage	10^3m^3	0.7368	2,939,543	21,660	3,168,231	23,345
4	Total Rate M1				389,166		419,442
	Rate M2						
5	Monthly Charge	bills	$ 70.00	81,451	5,702	93,396	6,538
6	Delivery Commodity Charge (avg rate)	10^3m^3	3.8103	975,571	37,173	1,118,641	42,624
7	Storage		0.7550	975,571	7,366	1,118,641	8,446
8	Total Rate M2				50,240		57,608
	Rate M4						
	Monthly Demand Charge						
9	First 8 450 m^3	10^3m^3/d	46.6239	12,905	6,017	21,678	10,107
10	Next 19 700 m^3	10^3m^3/d	20.9050	7,864	1,644	20,705	4,328
11	All over 28 150 m^3	10^3m^3/d	17.5631	4,507	792	3,953	694
	Delivery Commodity Charge						
12	First Block	10^3m^3	0.9621	396,153	3,811	667,121	6,418
13	All remaining use	10^3m^3	0.4243	8,525	36	128	1
	Interruptible						
14	Monthly Charge	bills	$ 690.00	-	-	77	53
15	Delivery Commodity Charge (Avg Price)	10^3m^3	2.2413	-	-	6,761	152
16	Interruptible Delivery Charge - Days Use Discount						-0.24
17	Total Rate M4				12,300		21,753
	Rate M5A						
	Firm Contracts						
18	Monthly Demand Charge	10^3m^3/d	28.6252	626	179	657	188
19	Delivery Commodity Charge	10^3m^3	1.9377	17,385	337	8,256	160
	Interruptible Contracts						
20	Monthly Charge	bills	$ 690.00	1,692	1,167	514	355
21	Delivery Commodity Charge (Avg Price)	10^3m^3	2.2413	517,747	11,604	65,708	1,473
22	Total Rate M5A				13,288		2,176
	Rate M7						
	Firm Contracts						
23	Monthly Demand Charge	10^3m^3/d	25.3924	14,220	3,611	34,256	8,698
24	Delivery Commodity Charge	10^3m^3	0.3206	142,488	457	446,541	1,432
	Interruptible / Seasonal Contracts						
25	Delivery Commodity Charge	10^3m^3	1.2747	4,655	59	94,802	1,208
26	Total Rate M7				4,127		11,338
	Rate M9						
27	Monthly Demand Charge	10^3m^3/d	15.1688	3,993	606	5,991	909
28	Delivery Commodity Charge	10^3m^3	0.1990	60,750	121	103,989	207
29	Total Rate M9				727		1,116
	Rate M10						
30	Delivery Commodity Charge	10^3m^3	5.1734	189	10	391	20
31	Total Rate M10				10		20

UNION RATE ZONES
Calculation of 2019 and 2013 Revenue at 2013 Approved Rates

Line No.	Particulars	Billing Units	Rates (cents / m^3)	2013 Approved Usage	2013 Revenue ($000's)	2019 Actual Usage	2019 Revenue ($000's)
		(a)	(b)	(c)	(d)	(e)	(f)
	Rate T1						
	Storage ($/GJ's)						
	Demand						
	Firm injection / withdrawal						
1	Union provides deliverability inventory	GJ/d	1.624	492,360	800	636,303	1,033
2	Customer provides deliverability inventory	GJ/d	1.197	166,800	200	1,770	2
3	Incremental firm injection right	GJ/d	1.197	-	-	-	-
4	Interruptible	GJ/d	1.197	62,244	75	-	-
5	Space	GJ/d	0.011	22,396,680	253	17,255,651	195
6	Commodity (Customer Provides)	GJ	0.008	2,750,300	21	4,997,528	38
7	Commodity (Union Provides)	GJ	0.030	-	-	-	-
		GJ					
	Transportation (cents/m^3)						
	Demand						
8	First 28 150 m^3	10^3m^3/d	31.9554	12,448	3,978	14,049	4,489
9	Next 112 720 m^3	10^3m^3/d	22.0775	13,002	2,871	11,784	2,602
	Commodity						
10	Firm	10^3m^3	0.0712	485,700	346	402,243	286
11	Interruptible	10^3m^3	1.2341	63,286	781	35,129	434
12	Monthly Charges		$ 1,936.13	528	1,022	539	1,044
13	Total Rate T1				10,345		10,123
	Rate T2						
	Storage ($/GJ's)						
	Demand						
	Firm injection / withdrawal						
14	Union provides deliverability inventory	GJ/d	1.624	1,516,920	2,463	2,071,408	3,364
15	Customer provides deliverability inventory	GJ/d	1.197	1,336,556	1,600	879,000	1,052
16	Incremental firm injection right	GJ/d	1.197	-	-	22,800	27
17	Interruptible	GJ/d	1.197	415,704	498	180,000	215
18	Space	GJ/d	0.011	106,645,056	1,204	103,996,826	1,175
19	Commodity (Customer Provides)	GJ	0.008	7,869,782	60	33,800,067	257
20	Commodity (Union Provides)	GJ	0.030	-	-		-
	Transportation (cents/m^3)						
	Demand						
21	First 140 870 m^3	10^3m^3/d	20.191	49,971	10,090	59,066	11,926
22	All Over 140 870 m^3	10^3m^3/d	10.680	167,088	17,845	219,092	23,399
	Commodity						
23	Firm	10^3m^3	0.008	4,521,813	353	3,998,055	312
24	Interruptible	10^3m^3	0.945	358,485	3,387	138,333	1,307
25	Monthly Charges	Meter/mo.	$ 6,000.00	444	2,664	508	3,048
26	Total Rate T2				40,164		46,083
	Rate T3						
	Storage ($/GJ's)						
	Demand						
	Firm injection / withdrawal						
27	Union provides deliverability inventory	GJ/d	1.624	-	-	-	-
28	Customer provides deliverability inventory	GJ/d	1.197	679,320	813	649,668	778
29	Incremental firm injection right	GJ/d	1.197	-	-	-	-
30	Interruptible	GJ/d	1.197	-	-	-	-
31	Space	GJ/d	0.011	36,614,256	414	38,472,252	435
32	Commodity (Customer Provides)	GJ	0.008	4,459,672	34	4,863,845	37
33	Commodity (Union Provides)	GJ	0.030	-	-		-
	Transportation (cents/ m^3)						
34	Demand	10^3m^3/d	9.358	28,200	2,639	28,200	2,639
35	Commodity	10^3m^3	0.011	272,712	29	283,352	30
36	Monthly Charges	Meter/mo.	$ 20,371.35	12	244	12	244
37	Total Rate T3				4,173		4,163
38	Total Union South In-franchise				524,540		573,822

UNION RATE ZONES
Calculation of 2019 and 2013 Revenue at 2013 Approved Rates

Line No.	Particulars	Billing Units (a)	Rates ($/GJ) (b)	2013 Approved Usage (c)	2013 Revenue ($000's) (d)	2019 Actual Usage (e)	2019 Revenue ($000's) (f)
	Rate M12						
	Demand						
1	Dawn to Kirkwall	GJ/d	2.011	8,708,176	17,509	1,409,148	2,833
2	Dawn to Kirkwall F24-T	GJ/d	0.068	594,000	40	594,000	40
3	Dawn to Parkway	GJ/d	2.382	43,052,600	102,570	53,984,063	128,613
4	Dawn to Parkway F24-T	GJ/d	0.068	4,711,848	319	6,437,148	436
5	Kirkwall to Parkway	GJ/d	0.372	1,411,468	525	5,053,860	1,879
6	M12-X Easterly & Westerly	GJ/d	2.961	4,692,132	13,896	4,752,132	14,073
7	Total Rate M12				134,859		147,875
	Rate M13						
8	Monthly Fixed Charge	monthly	$ 926.60	15	167	8	93
9	Transmission Commodity Charge	GJ	0.034	5,934,507	200	2,440,295	82
10	Total Rate M13				367		175
	Rate M16						
11	Monthly Fixed Charge	monthly	$ 1,474.12	4	71	3	53
12	Transmission Commodity Charge	GJ	0.034	6,236,394	211	5,234,919	177
13	Monthly Demand Charge - West of Dawn	GJ/d	1.059	214,154	227	214,154	227
14	Monthly Demand Charge - East of Dawn	GJ/d	0.741	108,800	81	-	-
15	Total Rate M16				589		456
	Rate C1						
	Storage Services						
16	Peak Storage (Short-term)	GJ			7,883		2,125
17	Balancing	GJ			2,000		2,678
18	Loans	GJ					2
19	Off Peak Storage	GJ			500		418
	Short-term Storage and Other Balancing Services						
20	Deferral Account Balance						1,194
	Transportation Services						
	Demand						
21	Ojibway to Dawn	GJ/d	1.059	1,025,520	1,197	695,316	737
22	St. Clair to Dawn	GJ/d	1.059		2,000	-	-
23	Parkway to Dawn	GJ/d	0.579	4,331,523	2,508	7,847,046	4,544
24	Kirkwall to Dawn	GJ/d	1.021	-	-	5,860,092	5,984
25	Bluewater to Dawn	GJ/d	1.059	-	-	615,000	651
26	Dawn to Parkway	GJ/d	2.382	84,780	413	510,022	1,215
27	Dawn to Dawn-Vector	GJ/d	0.029	1,114,140	32	1,114,140	32
28	Dawn to Dawn (TCPL)	GJ/d	0.134	6,000,000	805	6,000,000	805
29	Short-term Transportation	GJ			11,067		9,076
30	Exchanges				14,918		5,963
31	Ratepayer portion Exchange Revenue				(13,426)		(5,367)
32	Other Transactional				1,067		1,117
33	Total Rate C1				30,963		31,174
34	Total Ex-Franchise				166,778		179,680
35	Grand Total				924,039		1,004,980

SUMMARY
RETURN ON RATE BASE & EQUITY & EARNINGS SHARING DETERMINATION
ENBRIDGE GAS INC.

ONTARIO UTILITY
FOR THE YEAR ENDED DECEMBER 31, 2019

Line No.	Col. 1 Description	Col. 2 Reference	Col. 3 Actual
1.	**Part A) Return on Rate Base & Revenue (Deficiency) / Sufficiency**		
			($Millions) & (%'s)
2.	Utility Income before Income Tax	(Ex. B, Tab 1, Sch. 2)	919.7
3.	Less: Income Taxes	(Ex. B, Tab 1, Sch. 3)	59.9
4.	**Utility Income**		**859.9**
5.	**Utility Rate Base**	(Ex. B, Tab 1, Sch. 4)	**13,139.0**
6.	Indicated Return on Rate Base %	(line 4 / line 5)	6.544%
7.	Less: Required Rate of Return %	(Ex. B, Tab 1, Sch. 5)	6.546%
8.	**(Deficiency) / Sufficiency %**		**-0.002%**
9.	Net Earnings (Deficiency) / Sufficiency	(line 5 x line 8)	(0.3)
10.	Provision for Income Taxes		(0.1)
11.	**Gross Earnings (Deficiency) / Sufficiency**	(line 9 / 73.5%)	**(0.3)**
12.	**50% Earnings sharing to ratepayers**	(if line 11 > 1, line 11 x 50%)	-
13.	**Part B) Return on Equity & Revenue (Deficiency) / Sufficiency**		
14.	Utility Income before Income Tax	(Ex. B, Tab 1, Sch. 2)	919.7
15.	Less: Long Term Debt Costs	(Ex. B, Tab 1, Sch. 5)	356.1
16.	Less: Short Term Debt Costs	(Ex. B, Tab 1, Sch. 5)	8.3
17.	Less: Cost of Preferred Capital	(Ex. B, Tab 1, Sch. 5)	0.0
18.	Net Income before Income Taxes		555.3
19.	Less: Income Taxes	(Ex. B, Tab 1, Sch. 3)	59.9
20.	**Net Income Applicable to Common Equity**	(line 18 - line 19)	**495.5**
21.	Common Equity	(Ex. B, Tab 1, Sch. 5)	4,730.0
22.	Approved ROE (including deadband before earning sharing) %	(Board-approved + 150bp)	10.480%
23.	Achieved Rate of Return on Equity %	(line 20 / line 21)	10.475%
24.	**Resulting (Deficiency) / Sufficiency in Return on Equity %**		**-0.005%**
25.	Net Earnings (Deficiency) / Sufficiency	(line 21 x line 24)	(0.3)
26.	Provision for Income Taxes		(0.1)
27.	**Gross Earnings (Deficiency) / Sufficiency**	**(line 25 / 73.5%)**	**(0.3)**
28.	**50% Earnings sharing to ratepayers**	(if line 27 > 1, line 27 x 50%)	-

N/A - INTENTIONALLY LEFT BLANK

EGD RATE ZONE
St. Laurent NPS 12 Replacement Phase 3 - ICM Project Revenue Requirement

Line No.	Particulars ($000's)	2021 (a)	2022 (b)	2023 (c)	Average Annual (5) (d)
	Incremental Rate Base Investment				
1	Capital Expenditures	13,035	-	-	
2	Average Rate Base	543	12,905	12,646	
	Incremental Revenue Requirement Calculation:				
	Return on Incremental Rate Base: (1)				
3	Long-term Debt Interest	16	375	368	253
4	Short-term Debt Interest	0	1	1	1
5	Preference Shares	0	6	6	4
6	Equity	18	418	410	282
7	Total Return on Incremental Rate Base	34	800	784	539
	Incremental Operating Expenses:				
8	Depreciation Expense (2)	-	259	259	173
9	Total Incremental Operating Expenses	-	259	259	173
	Incremental Income Taxes:				
10	Return on Equity and Preference Shares (line 5 + line 6)	18	424	415	286
	Utility Timing Differences				
11	Add: Depreciation Expense (line 8)	-	259	259	173
12	Less: Current Year Tax Deductions	(2,061)	(658)	(619)	(1,113)
13	Taxable Income (line 10 + line 11 + line 12)	(2,043)	25	56	(654)
14	Income Taxes Before Gross Up (line 13 x 26.5%) (3)	(541)	7	15	(173)
15	Total Incremental Income Taxes After Gross Up (line 14 / (1-26.5%) (3) (4)	(737)	9	20	(236)
16	Total Incremental Revenue Requirement (line 7 + line 9 + line 15)	(703)	1,068	1,063	476

Notes:

(1) The return on rate base is calculated based on EGD's 2018 Board-approved capital structure:

Capital Structure	Component %	Cost Rate	Return Component
Long-term Debt	61.84%	4.70%	2.91%
Short-term Debt	0.56%	1.60%	0.01%
Preference Shares	1.60%	2.72%	0.04%
Equity	36.00%	9.00%	3.24%
Total	100.00%		6.20%

(2) Depreciation expense at Board-approved depreciation rates.

(3) Enbridge Gas's current provincial and federal tax rate is equal to 26.5%.

(4) Incremental taxes related to utility timing differences are negative as the capital cost allowance deduction in arriving at taxable income exceeds the provision of book depreciation in the year.

(5) Average annual revenue requirement calculated as the total revenue requirement from 2021 to 2023 recovered over the 36-month period from January 1, 2021 to December 31, 2023 expressed as an annual amount (12 months).

UNION RATE ZONES
London Line Replacement - ICM Project Revenue Requirement

Line No.	Particulars ($000's)	2021	2022	2023	Average Annual (5)
		(a)	(b)	(c)	(d)
	Incremental Rate Base Investment				
1	Capital Expenditures	124,039	-	-	
2	Average Rate Base	5,168	122,266	118,721	
	Incremental Revenue Requirement Calculation:				
	Return on Incremental Rate Base: (1)				
3	Long-term Debt Interest	207	4,894	4,752	3,284
4	Short-term Debt Interest	(0)	(1)	(1)	(0)
5	Preference Shares	4	102	99	69
6	Equity	166	3,931	3,817	2,638
7	Total Return on Incremental Rate Base	377	8,926	8,668	5,990
	Incremental Operating Expenses:				
8	Depreciation Expense (2)	-	3,545	3,545	2,363
9	Total Incremental Operating Expenses	-	3,545	3,545	2,363
	Incremental Income Taxes:				
10	Return on Equity and Preference Shares (line 5 + line 6)	170	4,033	3,916	2,706
	Utility Timing Differences				
11	Add: Depreciation Expense (line 8)	-	3,545	3,545	2,363
12	Less: Current Year Tax Deductions	(18,989)	(6,206)	(5,834)	(10,343)
13	Taxable Income (line 10 + line 11 + line 12)	(18,818)	1,372	1,627	(5,273)
14	Income Taxes Before Gross Up (line 13 x 26.5%) (3)	(4,987)	364	431	(1,397)
15	Total Incremental Income Taxes After Gross Up (line 14 / (1-26.5%) (3) (4)	(6,785)	495	587	(1,901)
16	Total Incremental Revenue Requirement (line 7 + line 9 + line 15)	(6,408)	12,966	12,799	6,453

Notes:

(1) The return on rate base is calculated based on Union's 2013 Board-approved capital structure:

Capital Structure	Component %	Cost Rate	Return Component
Long-term Debt	61.30%	6.53%	4.00%
Short-term Debt	-0.03%	1.31%	0.00%
Preference Shares	2.74%	3.05%	0.08%
Equity	36.00%	8.93%	3.21%
Total	100.00%		7.30%

(2) Depreciation expense at Board-approved depreciation rates.

(3) Enbridge Gas's current provincial and federal tax rate is equal to 26.5%.

(4) Incremental taxes related to utility timing differences are negative as the capital cost allowance deduction in arriving at taxable income exceeds the provision of book depreciation in the year.

(5) Average annual revenue requirement calculated as the total revenue requirement from 2021 to 2023 recovered over the 36-month period from January 1, 2021 to December 31, 2023 expressed as an annual amount (12 months).

UNION RATE ZONES
Sarnia Industrial Line Reinforcement - ICM Project Revenue Requirement

Line No.	Particulars ($000's)	2021 (a)	2022 (b)	2023 (c)	Average Annual (5) (d)
	Incremental Rate Base Investment				
1	Capital Expenditures	28,787	-	-	
2	Average Rate Base	3,332	28,388	27,703	
	Incremental Revenue Requirement Calculation:				
	Return on Incremental Rate Base: (1)				
3	Long-term Debt Interest	133	1,136	1,109	793
4	Short-term Debt Interest	(0)	(0)	(0)	(0)
5	Preference Shares	3	24	23	17
6	Equity	107	913	891	637
7	Total Return on Incremental Rate Base	243	2,073	2,023	1,446
	Incremental Operating Expenses:				
8	Depreciation Expense (2)	57	685	685	475
9	Total Incremental Operating Expenses	57	685	685	475
	Incremental Income Taxes:				
10	Return on Equity and Preference Shares (line 5 + line 6)	110	936	914	653
	Utility Timing Differences				
11	Add: Depreciation Expense (line 8)	57	685	685	475
12	Less: Current Year Tax Deductions	(5,111)	(1,759)	(1,626)	(2,832)
13	Taxable Income (line 10 + line 11 + line 12)	(4,944)	(138)	(28)	(1,703)
14	Income Taxes Before Gross Up (line 13 x 26.5%) (3)	(1,310)	(37)	(7)	(451)
15	Total Incremental Income Taxes After Gross Up (line 14 / (1-26.5%) (3) (4)	(1,782)	(50)	(10)	(614)
16	Total Incremental Revenue Requirement (line 7 + line 9 + line 15)	(1,482)	2,707	2,697	1,307

Notes:

(1) The return on rate base is calculated based on Union's 2013 Board-approved capital structure:

Capital Structure	Component %	Cost Rate	Return Component
Long-term Debt	61.30%	6.53%	4.00%
Short-term Debt	-0.03%	1.31%	0.00%
Preference Shares	2.74%	3.05%	0.08%
Equity	36.00%	8.93%	3.21%
Total	100.00%		7.30%

(2) Depreciation expense at Board-approved depreciation rates.

(3) Enbridge Gas's current provincial and federal tax rate is equal to 26.5%.

(4) Incremental taxes related to utility timing differences are negative as the capital cost allowance deduction in arriving at taxable income exceeds the provision of book depreciation in the year.

(5) Average annual revenue requirement calculated as the total revenue requirement from 2021 to 2023 recovered over the 36-month period from January 1, 2021 to December 31, 2023 expressed as an annual amount (12 months).

EGD RATE ZONE
Allocation of 2021 ICM Project Revenue Requirement

Line No.	Particulars	Delivery Demand LP Allocator (1) %	St. Laurent NPS 12 Replacement Phase 3 Project (2) (000's)
		(a)	(b)
	EGD		
1	Rate 1	51%	244
2	Rate 6	45%	212
3	Rate 9	0%	0
4	Rate 100	0%	1
5	Rate 110	3%	15
6	Rate 115	1%	3
7	Rate 125	0%	0
8	Rate 135	0%	0
9	Rate 145	0%	0
10	Rate 170	0%	0
11	Rate 200	0%	0
12	Rate 300	0%	0
13	Total	100%	476

Notes:

(1) St. Laurent NPS 12 Replacement Phase 3 project replaces the current extra high pressure Steel MAINS with three segments of low pressure plastic MAINS. Low pressure MAINS are allocated according to the Board approved cost allocation methodology (EB-2017-0086), Delivery Demand LP allocator, reflecting 2021 forecast peak demand by rate class

(2) Exhibit B, Tab 2, Appendix E

UNION RATE ZONES
Allocation of 2021 ICM Project Revenue Requirement

Line No.	Particulars	London Line Replacement: Distribution Demand Allocator (1) ($10^3m^3/d$)	London Line Replacement: Project 2021 ICM Allocation (2) ($000's)		Sarnia Industrial Line Reinforcement: Other Transmission Demand Allocator (4) ($10^3m^3/d$)	Sarnia Industrial Line Reinforcement: Project 2021 ICM Allocation (5) ($000's)		2021 ICM Allocation ($000's)
		(a)	(b)		(c)	(d)		(e) = (b) + (d)
1	Rate 01	-	-		-	-		-
2	Rate 10	-	-		-	-		-
3	Rate 20	-	-		-	-		-
4	Rate 25	-	-		-	-		-
5	Rate 100	-	-		-	-		-
6	Total Union North	-	-		-	-		-
7	Rate M1	30,972	3,387		30,972	495		3,882
8	Rate M2	11,797	1,290		11,797	189		1,479
9	Rate M4 (F)	4,581	501		4,756	76		577
10	Rate M4 (I)	1	0		-	-		0
11	Rate M5 (F)	59	6		59	1		7
12	Rate M5 (I)	325	36		-	-		36
13	Rate M7 (F)	3,126	342		3,756	60		402
14	Rate M7 (I)	541	59		-	-		59
15	Rate M9	-	-		545	9		9
16	Rate M10	-	-		5	0		0
17	Rate T1 (F)	2,129	233		2,129	34		267
18	Rate T1 (I)	-	-		-	-		-
19	Rate T2 (F)	4,018	439		25,297	404		844
20	Rate T2 (I)	1,461	160		-	-		160
21	Rate T3	-	-		2,475	40		40
22	Total Union South	59,011	6,453		81,791	1,307		7,760
23	Excess Utility Storage	-	-		-	-		-
24	Rate C1 (F)	-	-		-	-		-
25	Rate C1 (I)	-	-		-	-		-
26	Rate M12	-	-		-	-		-
27	Rate M13	-	-		-	-		-
28	Rate M16	-	-		-	-		-
29	Rate M17	-	-		-	-		-
30	Total Ex-Franchise	-	-		-	-		-
31	Total Union Rate Zones	59,011	6,453	(3)	81,791	1,307	(6)	7,760

Notes:
(1) Distribution demand allocation in proportion to forecast 2021 Union South in-franchise firm and interruptible design day demands, excluding demands served directly off transmission lines.
(2) Allocated in proportion to column (a).
(3) Exhibit B, Tab 2, Schedule 1, Appendix E, p. 2.
(4) Other transmission demand allocation in proportion to forecast 2021 Union South in-franchise firm design day demands.
(5) Allocated in proportion to column (c).
(6) Exhibit B, Tab 2, Schedule 1, Appendix E, p. 3.

EGD RATE ZONE
Deriviation of 2021 Incremental Capital Module ("ICM") Rates by Rate Class

Line No.	Particulars	ICM Revenue Requirement (1) (000's)	Forecast Volumes (10^6 m^3)	ICM Unit Rates (cents / m³)
		(a)	(b)	(d) = (a / b * 100)
	Bundled Services			
1	Rate 1	244	5,118.2	0.0048
2	Rate 6	212	4,923.0	0.0043
3	Rate 9	0	0.0	0.0000
4	Rate 100 - per m³ of contract demand	1	5.2	0.0123
5	Rate 110 - per m³ of contract demand	15	60.8	0.0254
6	Rate 115 - per m³ of contract demand	3	17.2	0.0159
7	Rate 135	0	63.8	0.0000
8	Rate 145 - per m³ of contract demand	0	7.2	0.0034
9	Rate 170 - per m³ of contract demand	0	28.6	0.0015
10	Rate 200 - per m³ of contract demand	0	14.8	0.0000
	Unbundled Services			
11	Rate 125 - per m³ of contract demand	0	111.1	0.0000
12	Rate 300 - per m³ of contract demand	0	0.2	0.0381
13	Total 2021 ICM Costs	476		

Notes:
(1) Exhibit B, Tab 2. Appendix F, Page 1

UNION RATE ZONES

Derivation of 2021 Incremental Capital Module ("ICM") Rates by Rate Class

Line No.	Particulars	ICM Revenue Requirement (1) ($000s)	2021 Forecast Usage	Billing Units	2021 ICM Rate (2) (cents / m³)
		(a)	(b)	(c)	(d) = (a / b * 100)
	Union South				
	Rate M1 Small Volume General Service				
1	Monthly Delivery Commodity Charge	3,882	3,142,868	10^3m^3	0.1235
	Rate M2 Large Volume General Service				
2	Monthly Delivery Commodity Charge	1,479	1,340,433	10^3m^3	0.1103
	Rate M4 Firm Commercial/Industrial Contract Rate				
	Firm Contracts				
3	Monthly Demand Charge	577	50,008	10^3m^3/d	1.1538
	Interruptible Contracts				
4	Monthly Delivery Commodity Charge	0	1,707	10^3m^3	0.0568
	Rate M5A Interruptible Commercial/Industrial Contract Rate				
	Firm Contracts				
5	Monthly Demand Charge	7	521	10^3m^3/d	1.4186
	Interruptible Contracts				
6	Delivery Commodity Charge (Avg Price)	36	61,190	10^3m^3	0.0568
	Rate M7 Special Large Volume Contract Rate				
	Firm Contracts				
7	Monthly Demand Charge	402	44,597	10^3m^3/d	0.9011
	Interruptible / Seasonal Contracts				
8	Monthly Delivery Commodity Charge	59	80,964	10^3m^3	0.0731
	Rate M9 Large Wholesale Service				
9	Monthly Demand Charge	9	6,040	10^3m^3/d	0.1442
	Rate M10 Small Wholesale Service				
10	Monthly Delivery Commodity Charge	0	391	10^3m^3	0.0186
	Rate T1 Contract Carriage Service				
	Firm Contracts				
11	Monthly Demand Charge	267	26,510	10^3m^3/d	1.0065
	Interruptible Contracts				
12	Interruptible Transportation Commodity Charge	-	35,053	10^3m^3	-
	Rate T2 Contract Carriage Service				
	Firm Contracts				
13	Monthly Demand Charge	844	282,300	10^3m^3/d	0.2988
	Interruptible Contracts				
14	Interruptible Transportation Commodity Charge	160	154,339	10^3m^3	0.1035
	Rate T3 Contract Carriage Service				
15	Monthly Demand Charge	40	28,200	10^3m^3/d	0.1403
16	Total Union South In-franchise	7,760			
17	Total Union In-franchise	7,760			

Notes:

(1) Exhibit B, Tab 2, Schedule 1, Appendix F, p. 2, column (e).

(2) To be included in delivery and transportation rates.

(3) The Interruptible Delivery Commodity Charge is calculated as a common unit rate for Rate M4 and Rate M5.

ANNUAL BILL COMPARISON - RESIDENTIAL CUSTOMERS

(A) EB-2020-0195 + 2021 ICM vs (B) EB-2020-0195

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Heating & Water Htg.				Heating, Water Htg. & Other Uses			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
1.1	VOLUME	m³	3,064	3,064	0	0.0%	4,691	4,691	0	0.0%
1.2	CUSTOMER CHG.	$	245.76	245.76	0.00	0.0%	245.76	245.76	0.00	0.0%
1.3	DISTRIBUTION CHG.	$	265.86	265.71	0.15	0.1%	400.88	400.65	0.22	0.1%
1.4	LOAD BALANCING	§ $	160.40	160.40	0.00	0.0%	245.58	245.58	0.00	0.0%
1.5	SALES COMMDTY	$	322.28	322.28	0.00	0.0%	493.41	493.41	0.00	0.0%
1.6	TOTAL SALES	$	994.30	994.15	0.15	0.0%	1,385.62	1,385.40	0.22	0.0%
1.7	TOTAL T-SERVICE	$	672.02	671.88	0.15	0.0%	892.22	891.99	0.22	0.0%
1.8	SALES UNIT RATE	$/m³	0.3245	0.3245	0.0000	0.0%	0.2954	0.2953	0.0000	0.0%
1.9	T-SERVICE UNIT RATE	$/m³	0.2193	0.2193	0.0000	0.0%	0.1902	0.1901	0.0000	0.0%
1.10	SALES UNIT RATE	$/GJ	8.4223	8.4210	0.0012	0.0%	7.6662	7.6650	0.0012	0.0%
1.11	T-SERVICE UNIT RATE	$/GJ	5.6924	5.6912	0.0012	0.0%	4.9363	4.9351	0.0012	0.0%

			Heating Only				Heating & Water Htg.			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
2.1	VOLUME	m³	1,955	1,955	0	0.0%	2,005	2,005	0	0.0%
2.2	CUSTOMER CHG.	$	245.76	245.76	0.00	0.0%	245.76	245.76	0.00	0.0%
2.3	DISTRIBUTION CHG.	$	170.51	170.41	0.09	0.1%	177.40	177.30	0.10	0.1%
2.4	LOAD BALANCING	§ $	102.35	102.35	0.00	0.0%	104.96	104.96	0.00	0.0%
2.5	SALES COMMDTY	$	205.63	205.63	0.00	0.0%	210.89	210.89	0.00	0.0%
2.6	TOTAL SALES	$	724.24	724.15	0.09	0.0%	739.01	738.92	0.10	0.0%
2.7	TOTAL T-SERVICE	$	518.61	518.52	0.09	0.0%	528.12	528.03	0.10	0.0%
2.8	SALES UNIT RATE	$/m³	0.3705	0.3704	0.0000	0.0%	0.3686	0.3685	0.0000	0.0%
2.9	T-SERVICE UNIT RATE	$/m³	0.2653	0.2652	0.0000	0.0%	0.2634	0.2634	0.0000	0.0%
2.10	SALES UNIT RATE	$/GJ	9.6148	9.6135	0.0012	0.0%	9.5662	9.5649	0.0012	0.0%
2.11	T-SERVICE UNIT RATE	$/GJ	6.8849	6.8837	0.0012	0.0%	6.8363	6.8351	0.0012	0.0%

§ The Load Balancing Charge is included in the Delivery Charge in the applicable rate Schedule.

ANNUAL BILL COMPARISON - RESIDENTIAL CUSTOMERS

(A) EB-2020-0195 + 2021 ICM vs (B) EB-2020-0195

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Heating, Pool Htg. & Other Uses				General & Water Htg.			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
3.1	VOLUME	m³	5,048	5,048	0	0.0%	1,081	1,081	0	0.0%
3.2	CUSTOMER CHG.	$	245.76	245.76	0.00	0.0%	245.76	245.76	0.00	0.0%
3.3	DISTRIBUTION CHG.	$	431.12	430.88	0.24	0.1%	100.09	100.03	0.05	0.1%
3.4	LOAD BALANCING	§ $	264.27	264.27	0.00	0.0%	56.59	56.59	0.00	0.0%
3.5	SALES COMMDTY	$	530.96	530.96	0.00	0.0%	113.70	113.70	0.00	0.0%
3.6	TOTAL SALES	$	1,472.11	1,471.87	0.24	0.0%	516.14	516.09	0.05	0.0%
3.7	TOTAL T-SERVICE	$	941.15	940.91	0.24	0.0%	402.44	402.39	0.05	0.0%
3.8	SALES UNIT RATE	$/m³	0.2916	0.2916	0.0000	0.0%	0.4775	0.4774	0.0000	0.0%
3.9	T-SERVICE UNIT RATE	$/m³	0.1864	0.1864	0.0000	0.0%	0.3723	0.3722	0.0000	0.0%
3.10	SALES UNIT RATE	$/GJ	7.5687	7.5675	0.0012	0.0%	12.3920	12.3908	0.0012	0.0%
3.11	T-SERVICE UNIT RATE	$/GJ	4.8388	4.8376	0.0012	0.0%	9.6621	9.6609	0.0012	0.0%

			Heating & Water Htg.				Heating & Water Htg.			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
2.1	VOLUME	m³	2,480	2,480	0	0.0%	2,400	2,400	0	0.0%
2.2	CUSTOMER CHG.	$	245.76	245.76	0.00	0.0%	245.76	245.76	0.00	0.0%
2.3	DISTRIBUTION CHG.	$	217.05	216.94	0.12	0.1%	210.11	209.99	0.11	0.1%
2.4	LOAD BALANCING	§ $	129.83	129.83	0.00	0.0%	125.64	125.64	0.00	0.0%
2.5	SALES COMMDTY	$	260.85	260.85	0.00	0.0%	252.44	252.44	0.00	0.0%
2.6	TOTAL SALES	$	853.50	853.38	0.12	0.0%	833.94	833.83	0.11	0.0%
2.7	TOTAL T-SERVICE	$	592.65	592.53	0.12	0.0%	581.51	581.39	0.11	0.0%
2.8	SALES UNIT RATE	$/m³	0.3442	0.3441	0.0000	0.0%	0.3475	0.3474	0.0000	0.0%
2.9	T-SERVICE UNIT RATE	$/m³	0.2390	0.2389	0.0000	0.0%	0.2423	0.2422	0.0000	0.0%
2.10	SALES UNIT RATE	$/GJ	8.9320	8.9308	0.0012	0.0%	9.0183	9.0171	0.0012	0.0%
2.11	T-SERVICE UNIT RATE	$/GJ	6.2022	6.2009	0.0012	0.0%	6.2885	6.2872	0.0012	0.0%

§ The Load Balancing Charge is included in the Delivery Charge in the applicable rate Schedule.

ANNUAL BILL COMPARISON - COMMERCIAL & INDUSTRIAL CUSTOMERS

(A) EB-2020-0195 + 2021 ICM vs (B) EB-2020-0195

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Commercial Heating & Other Uses				**Com. Htg., Air Cond'ng & Other Uses**			
			(A)	**(B)**	**CHANGE**		**(A)**	**(B)**	**CHANGE**	
					(A) - (B)	%			(A) - (B)	%
1.1	VOLUME	m³	22,606	22,606	0	0.0%	29,278	29,278	0	0.0%
1.2	CUSTOMER CHG.	$	860.16	860.16	0.00	0.0%	860.16	860.16	0.00	0.0%
1.3	DISTRIBUTION CHG.	$	1,556.76	1,555.79	0.97	0.1%	1,997.56	1,996.29	1.26	0.1%
1.4	LOAD BALANCING	§ $	1,166.09	1,166.09	0.00	0.0%	1,510.25	1,510.25	0.00	0.0%
1.5	SALES COMMDTY	$	2,382.66	2,382.66	0.00	0.0%	3,085.89	3,085.89	0.00	0.0%
1.6	TOTAL SALES	$	5,965.67	5,964.70	0.97	0.0%	7,453.86	7,452.59	1.26	0.0%
1.7	TOTAL T-SERVICE	$	3,583.01	3,582.04	0.97	0.0%	4,367.97	4,366.71	1.26	0.0%
1.8	SALES UNIT RATE	$/m³	0.2639	0.2639	0.0000	0.0%	0.2546	0.2545	0.0000	0.0%
1.9	T-SERVICE UNIT RATE	$/m³	0.1585	0.1585	0.0000	0.0%	0.1492	0.1491	0.0000	0.0%
1.10	SALES UNIT RATE	$/GJ	6.8491	6.8480	0.0011	0.0%	6.6076	6.6064	0.0011	0.0%
1.11	T-SERVICE UNIT RATE	$/GJ	4.1136	4.1125	0.0011	0.0%	3.8720	3.8709	0.0011	0.0%
			Medium Commercial Customer				**Large Commercial Customer**			
			(A)	**(B)**			**(A)**	**(B)**	**CHANGE**	
					(A) - (B)	%			(A) - (B)	%
2.1	VOLUME	m³	169,563	169,563	0	0.0%	339,125	339,125	0	0.0%
2.2	CUSTOMER CHG.	$	860.16	860.16	0.00	0.0%	860.16	860.16	0.00	0.0%
2.3	DISTRIBUTION CHG.	$	8,409.15	8,401.84	7.31	0.1%	15,411.91	15,397.30	14.61	0.1%
2.4	LOAD BALANCING	§ $	8,746.61	8,746.61	0.00	0.0%	17,493.17	17,493.17	0.00	0.0%
2.5	SALES COMMDTY	$	17,871.86	17,871.86	0.00	0.0%	35,743.61	35,743.61	0.00	0.0%
2.6	TOTAL SALES	$	35,887.77	35,880.46	7.31	0.0%	69,508.85	69,494.24	14.61	0.0%
2.7	TOTAL T-SERVICE	$	18,015.91	18,008.61	7.31	0.0%	33,765.24	33,750.63	14.61	0.0%
2.8	SALES UNIT RATE	$/m³	0.2116	0.2116	0.0000	0.0%	0.2050	0.2049	0.0000	0.0%
2.9	T-SERVICE UNIT RATE	$/m³	0.1062	0.1062	0.0000	0.0%	0.0996	0.0995	0.0000	0.0%
2.10	SALES UNIT RATE	$/GJ	5.4931	5.4920	0.0011	0.0%	5.3196	5.3185	0.0011	0.0%
2.11	T-SERVICE UNIT RATE	$/GJ	2.7576	2.7564	0.0011	0.0%	2.5841	2.5830	0.0011	0.0%

§ The Load Balancing Charge is included in the Delivery Charge in the applicable rate Schedule.

ANNUAL BILL COMPARISON - COMMERCIAL & INDUSTRIAL CUSTOMERS

(A) EB-2020-0195 + 2021 ICM vs (B) EB-2020-0195

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Industrial General Use				**Industrial Heating & Other Uses**			
			(A)	**(B)**	**CHANGE**		**(A)**	**(B)**	**CHANGE**	
					(A) - (B)	%			(A) - (B)	%
3.1	VOLUME	m³	43,285	43,285	0	0.0%	63,903	63,903	0	0.0%
3.2	CUSTOMER CHG.	$	860.16	860.16	0.00	0.0%	860.16	860.16	0.00	0.0%
3.3	DISTRIBUTION CHG.	$	2,761.63	2,759.76	1.87	0.1%	3,707.03	3,704.27	2.75	0.1%
3.4	LOAD BALANCING	§ $	2,232.78	2,232.78	0.00	0.0%	3,296.32	3,296.32	0.00	0.0%
3.5	SALES COMMDTY	$	4,562.22	4,562.22	0.00	0.0%	6,735.34	6,735.34	0.00	0.0%
3.6	TOTAL SALES	$	10,416.78	10,414.92	1.87	0.0%	14,598.85	14,596.10	2.75	0.0%
3.7	TOTAL T-SERVICE	$	5,854.57	5,852.70	1.87	0.0%	7,863.51	7,860.76	2.75	0.0%
3.8	SALES UNIT RATE	$/m³	0.2407	0.2406	0.0000	0.0%	0.2285	0.2284	0.0000	0.0%
3.9	T-SERVICE UNIT RATE	$/m³	0.1353	0.1352	0.0000	0.0%	0.1231	0.1230	0.0000	0.0%
3.10	SALES UNIT RATE	$/GJ	6.2459	6.2448	0.0011	0.0%	5.9292	5.9281	0.0011	0.0%
3.11	T-SERVICE UNIT RATE	$/GJ	3.5104	3.5093	0.0011	0.0%	3.1937	3.1926	0.0011	0.0%
			Medium Industrial Customer				**Large Industrial Customer**			
			(A)	**(B)**	**CHANGE**		**(A)**	**(B)**	**CHANGE**	
					(A) - (B)	%			(A) - (B)	%
4.1	VOLUME	m³	169,563	169,563	0	0.0%	339,124	339,124	0	0.0%
4.2	CUSTOMER CHG.	$	860.16	860.16	0.00	0.0%	860.16	860.16	0.00	0.0%
4.3	DISTRIBUTION CHG.	$	8,609.19	8,601.88	7.31	0.1%	15,560.76	15,546.14	14.61	0.1%
4.4	LOAD BALANCING	§ $	8,746.61	8,746.61	0.00	0.0%	17,493.11	17,493.11	0.00	0.0%
4.5	SALES COMMDTY	$	17,871.86	17,871.86	0.00	0.0%	35,743.50	35,743.50	0.00	0.0%
4.6	TOTAL SALES	$	36,087.82	36,080.51	7.31	0.0%	69,657.53	69,642.92	14.61	0.0%
4.7	TOTAL T-SERVICE	$	18,215.96	18,208.65	7.31	0.0%	33,914.03	33,899.42	14.61	0.0%
4.8	SALES UNIT RATE	$/m³	0.2128	0.2128	0.0000	0.0%	0.2054	0.2054	0.0000	0.0%
4.9	T-SERVICE UNIT RATE	$/m³	0.1074	0.1074	0.0000	0.0%	0.1000	0.1000	0.0000	0.0%
4.10	SALES UNIT RATE	$/GJ	5.5237	5.5226	0.0011	0.0%	5.3310	5.3299	0.0011	0.0%
4.11	T-SERVICE UNIT RATE	$/GJ	2.7882	2.7871	0.0011	0.0%	2.5955	2.5944	0.0011	0.0%

§ The Load Balancing Charge is included in the Delivery Charge in the applicable rate Schedule.

ANNUAL BILL COMPARISON - LARGE VOLUME CUSTOMERS

(A) EB-2020-0195 + 2021 ICM vs (B) EB-2020-0195

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Rate 100 - Small Commercial Firm				**Rate 100 - Average Commercial Firm**			
			(A)	**(B)**	**CHANGE** (A) - (B)	%	**(A)**	**(B)**	**CHANGE** (A) - (B)	%
1.1	VOLUME	m³	339,188	339,188	0	0.0%	598,567	598,567	0	0.0%
1.2	CUSTOMER CHG.	$	1,499.16	1,499.16	0.00	0.0%	1,499.16	1,499.16	0.00	0.0%
1.3	DISTRIBUTION CHG.	$	13,878.73	13,874.30	4.43	0.0%	67,610.94	67,588.74	22.20	0.0%
1.4	LOAD BALANCING	$	17,496.41	17,496.41	0.00	0.0%	30,876.02	30,876.02	0.00	0.0%
1.5	SALES COMMDTY	$	35,750.25	35,750.25	0.00	0.0%	63,088.67	63,088.67	0.00	0.0%
1.6	TOTAL SALES	$	68,624.56	68,620.13	4.43	0.0%	163,074.79	163,052.59	22.20	0.0%
1.7	TOTAL T-SERVICE	$	32,874.31	32,869.88	4.43	0.0%	99,986.12	99,963.92	22.20	0.0%
1.8	SALES UNIT RATE	$/m³	0.2023	0.2023	0.0000	0.0%	0.2724	0.2724	0.0000	0.0%
1.9	T-SERVICE UNIT RATE	$/m³	0.0969	0.0969	0.0000	0.0%	0.1670	0.1670	0.0000	0.0%
1.10	SALES UNIT RATE	$/GJ	5.2510	5.2506	0.0003	0.0%	7.0709	7.0699	0.0010	0.0%
1.11	T-SERVICE UNIT RATE	$/GJ	2.5155	2.5151	0.0003	0.0%	4.3354	4.3344	0.0010	0.0%

Rate 100 - Large Industrial Firm

			(A)	**(B)**	**CHANGE** (A) - (B)	%
2.1	VOLUME	m³	1,500,000	1,500,000	0	0.0%
2.2	CUSTOMER CHG.	$	1,499.16	1,499.16	0.00	0.0%
2.3	DISTRIBUTION CHG.	$	135,756.76	135,712.36	44.40	0.0%
2.4	LOAD BALANCING	$	77,374.85	77,374.85	0.00	0.0%
2.5	SALES COMMDTY	$	158,099.27	158,099.27	0.00	0.0%
2.6	TOTAL SALES	$	372,730.04	372,685.64	44.40	0.0%
2.7	TOTAL T-SERVICE	$	214,630.77	214,586.37	44.40	0.0%
2.8	SALES UNIT RATE	$/m³	0.2485	0.2485	0.0000	0.0%
2.9	T-SERVICE UNIT RATE	$/m³	0.1431	0.1431	0.0000	0.0%
2.10	SALES UNIT RATE	$/GJ	6.4492	6.4484	0.0008	0.0%
2.11	T-SERVICE UNIT RATE	$/GJ	3.7137	3.7129	0.0008	0.0%

ANNUAL BILL COMPARISON - LARGE VOLUME CUSTOMERS

(A) EB-2020-0195 + 2021 ICM vs (B) EB-2020-0195

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Rate 145 - Small Commercial Interr.				Rate 145 - Average Commercial Interr.			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
3.1	VOLUME	m^3	339,188	339,188	0	0.0%	598,568	598,568	0	0.0%
3.2	CUSTOMER CHG.	$	1,515.48	1,515.48	0.00	0.0%	1,515.48	1,515.48	0.00	0.0%
3.3	DISTRIBUTION CHG.	$	12,600.89	12,599.65	1.23	0.0%	19,129.16	19,127.31	1.85	0.0%
3.4	LOAD BALANCING	$	13,703.70	13,703.70	0.00	0.0%	24,183.55	24,183.55	0.00	0.0%
3.5	SALES COMMDTY	$	35,567.92	35,567.92	0.00	0.0%	62,767.01	62,767.01	0.00	0.0%
3.6	TOTAL SALES	$	63,387.98	63,386.75	1.23	0.0%	107,595.20	107,593.35	1.85	0.0%
3.7	TOTAL T-SERVICE	$	27,820.06	27,818.83	1.23	0.0%	44,828.19	44,826.34	1.85	0.0%
3.8	SALES UNIT RATE	$/m³	0.1869	0.1869	0.0000	0.0%	0.1798	0.1798	0.0000	0.0%
3.9	T-SERVICE UNIT RATE	$/m³	0.0820	0.0820	0.0000	0.0%	0.0749	0.0749	0.0000	0.0%
3.10	SALES UNIT RATE	$/GJ	4.8503	4.8502	0.0001	0.0%	4.6653	4.6652	0.0001	0.0%
3.11	T-SERVICE UNIT RATE	$/GJ	2.1287	2.1286	0.0001	0.0%	1.9437	1.9437	0.0001	0.0%
			Rate 145 - Small Industrial Interr.				Rate 145 - Average Industrial Interr.			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
4.1	VOLUME	m^3	339,188	339,188	0	0.0%	598,567	598,567	0	0.0%
4.2	CUSTOMER CHG.	$	1,515.48	1,515.48	0.00	0.0%	1,515.48	1,515.48	0.00	0.0%
4.3	DISTRIBUTION CHG.	$	12,876.68	12,875.45	1.23	0.0%	19,373.30	19,371.46	1.85	0.0%
4.4	LOAD BALANCING	$	13,703.70	13,703.70	0.00	0.0%	24,183.51	24,183.51	0.00	0.0%
4.5	SALES COMMDTY	$	35,567.92	35,567.92	0.00	0.0%	62,766.91	62,766.91	0.00	0.0%
4.6	TOTAL SALES	$	63,663.77	63,662.54	1.23	0.0%	107,839.20	107,837.35	1.85	0.0%
4.7	TOTAL T-SERVICE	$	28,095.85	28,094.62	1.23	0.0%	45,072.29	45,070.44	1.85	0.0%
4.8	SALES UNIT RATE	$/m³	0.1877	0.1877	0.0000	0.0%	0.1802	0.1802	0.0000	0.0%
4.9	T-SERVICE UNIT RATE	$/m³	0.0828	0.0828	0.0000	0.0%	0.0753	0.0753	0.0000	0.0%
4.10	SALES UNIT RATE	$/GJ	4.8714	4.8713	0.0001	0.0%	4.6759	4.6758	0.0001	0.0%
4.11	T-SERVICE UNIT RATE	$/GJ	2.1498	2.1497	0.0001	0.0%	1.9543	1.9542	0.0001	0.0%

ANNUAL BILL COMPARISON - LARGE VOLUME CUSTOMERS

(A) EB-2020-0195 + 2021 ICM vs (B) EB-2020-0195

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Rate 110 - Small Ind. Firm - 50% LF				**Rate 110 - Average Ind. Firm - 50% LF**			
			(A)	**(B)**	**CHANGE** (A) - (B)	%	**(A)**	**(B)**	**CHANGE** (A) - (B)	%
5.1	VOLUME	m³	598,568	598,568	0	0.0%	9,976,121	9,976,121	0	0.0%
5.2	CUSTOMER CHG.	$	7,217.16	7,217.16	0.00	0.0%	7,217.16	7,217.16	0.00	0.0%
5.3	DISTRIBUTION CHG.	$	14,438.86	14,428.83	10.03	0.1%	236,751.82	236,587.72	164.10	0.1%
5.4	LOAD BALANCING	$	25,817.66	25,817.66	0.00	0.0%	430,293.76	430,293.76	0.00	0.0%
5.5	SALES COMMDTY	$	62,744.94	62,744.94	0.00	0.0%	1,045,747.75	1,045,747.75	0.00	0.0%
5.6	TOTAL SALES	$	110,218.62	110,208.59	10.03	0.0%	1,720,010.50	1,719,846.39	164.10	0.0%
5.7	TOTAL T-SERVICE	$	47,473.68	47,463.65	10.03	0.0%	674,262.74	674,098.64	164.10	0.0%
5.8	SALES UNIT RATE	$/m³	0.1841	0.1841	0.0000	0.0%	0.1724	0.1724	0.0000	0.0%
5.9	T-SERVICE UNIT RATE	$/m³	0.0793	0.0793	0.0000	0.0%	0.0676	0.0676	0.0000	0.0%
5.10	SALES UNIT RATE	$/GJ	4.7791	4.7786	0.0004	0.0%	4.4748	4.4743	0.0004	0.0%
5.11	T-SERVICE UNIT RATE	$/GJ	2.0585	2.0580	0.0004	0.0%	1.7542	1.7537	0.0004	0.0%
			Rate 110 - Average Ind. Firm - 75% LF				**Rate 115 - Large Ind. Firm - 80% LF**			
			(A)	**(B)**	**CHANGE** (A) - (B)	%	**(A)**	**(B)**	**CHANGE** (A) - (B)	%
6.1	VOLUME	m³	9,976,120	9,976,120	0	0.0%	69,832,850	69,832,850	0	0.0%
6.2	CUSTOMER CHG.	$	7,217.16	7,217.16	0.00	0.0%	7,650.36	7,650.36	0.00	0.0%
6.3	DISTRIBUTION CHG.	$	188,357.6	188,246.73	110.92	0.1%	996,190.0	995,735.37	454.65	0.0%
6.4	LOAD BALANCING	$	430,293.72	430,293.72	0.00	0.0%	2,919,046.42	2,919,046.42	0.00	0.0%
6.5	SALES COMMDTY	$	1,045,747.65	1,045,747.65	0.00	0.0%	7,320,234.59	7,320,234.59	0.00	0.0%
6.6	TOTAL SALES	$	1,671,616.18	1,671,505.26	110.92	0.0%	11,243,121.39	11,242,666.74	454.65	0.0%
6.7	TOTAL T-SERVICE	$	625,868.53	625,757.61	110.92	0.0%	3,922,886.80	3,922,432.15	454.65	0.0%
6.8	SALES UNIT RATE	$/m³	0.1676	0.1676	0.0000	0.0%	0.1610	0.1610	0.0000	0.0%
6.9	T-SERVICE UNIT RATE	$/m³	0.0627	0.0627	0.0000	0.0%	0.0562	0.0562	0.0000	0.0%
6.10	SALES UNIT RATE	$/GJ	4.3489	4.3486	0.0003	0.0%	4.1786	4.1784	0.0002	0.0%
6.11	T-SERVICE UNIT RATE	$/GJ	1.6283	1.6280	0.0003	0.0%	1.4580	1.4578	0.0002	0.0%

ANNUAL BILL COMPARISON - LARGE VOLUME CUSTOMERS

(A) EB-2020-0195 + 2021 ICM vs (B) EB-2020-0195

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Rate 135 - Seasonal Firm				**Rate 170 - Average Ind. Interr. - 50% LF**			
			(A)	**(B)**	**CHANGE**		**(A)**	**(B)**	**CHANGE**	
					(A) - (B)	%			(A) - (B)	%
7.1	VOLUME	m³	598,567	598,567	0	0.0%	9,976,121	9,976,121	0	0.0%
7.2	CUSTOMER CHG.	$	1,414.08	1,414.08	0.00	0.0%	3,432.00	3,432.00	0.00	0.0%
7.3	DISTRIBUTION CHG.	$	11,009.8	11,009.66	0.16	0.0%	81,858.98	81,849.05	9.93	0.0%
7.4	LOAD BALANCING	$	19,470.53	19,470.53	0.00	0.0%	309,588.44	309,588.44	0.00	0.0%
7.5	SALES COMMDTY	$	62,787.75	62,787.75	0.00	0.0%	1,045,747.75	1,045,747.75	0.00	0.0%
7.6	TOTAL SALES	$	94,682.19	94,682.02	0.16	0.0%	1,440,627.16	1,440,617.23	9.93	0.0%
7.7	TOTAL T-SERVICE	$	31,894.44	31,894.28	0.16	0.0%	394,879.42	394,869.49	9.93	0.0%
7.8	SALES UNIT RATE	$/m³	0.1582	0.1582	0.0000	0.0%	0.1444	0.1444	0.0000	0.0%
7.9	T-SERVICE UNIT RATE	$/m³	0.0533	0.0533	0.0000	0.0%	0.0396	0.0396	0.0000	0.0%
7.10	SALES UNIT RATE	$/GJ	4.1054	4.1054	0.0000	0.0%	3.7479	3.7479	0.0000	0.0%
7.11	T-SERVICE UNIT RATE	$/GJ	1.3829	1.3829	0.0000	0.0%	1.0273	1.0273	0.0000	0.0%
			Rate 170 - Average Ind. Interr. - 75% LF				**Rate 170 - Large Ind. Interr. - 75% LF**			
			(A)	**(B)**	**CHANGE**		**(A)**	**(B)**	**CHANGE**	
					(A) - (B)	%			(A) - (B)	%
8.1	VOLUME	m³	9,976,120	9,976,120	0	0.0%	69,832,850	69,832,850	0	0.0%
8.2	CUSTOMER CHG.	$	3,432.00	3,432.00	0.00	0.0%	3,432.00	3,432.00	0.00	0.0%
8.3	DISTRIBUTION CHG.	$	74,470.14	74,463.43	6.71	0.0%	403,926.03	403,879.01	47.02	0.0%
8.4	LOAD BALANCING	$	309,588.41	309,588.41	0.00	0.0%	2,167,119.16	2,167,119.16	0.00	0.0%
8.5	SALES COMMDTY	$	1,045,747.64	1,045,747.64	0.00	0.0%	7,320,234.55	7,320,234.55	0.00	0.0%
8.6	TOTAL SALES	$	1,433,238.19	1,433,231.48	6.71	0.0%	9,894,711.74	9,894,664.72	47.02	0.0%
8.7	TOTAL T-SERVICE	$	387,490.55	387,483.83	6.71	0.0%	2,574,477.19	2,574,430.17	47.02	0.0%
8.8	SALES UNIT RATE	$/m³	0.1437	0.1437	0.0000	0.0%	0.1417	0.1417	0.0000	0.0%
8.9	T-SERVICE UNIT RATE	$/m³	0.0388	0.0388	0.0000	0.0%	0.0369	0.0369	0.0000	0.0%
8.10	SALES UNIT RATE	$/GJ	3.7287	3.7287	0.0000	0.0%	3.6774	3.6774	0.0000	0.0%
8.11	T-SERVICE UNIT RATE	$/GJ	1.0081	1.0081	0.0000	0.0%	0.9568	0.9568	0.0000	0.0%

ANNUAL BILL COMPARISON - RESIDENTIAL CUSTOMERS

INCLUDING FEDERAL CARBON PRICING IMPACTS FOR NON-OBPS PARTICIPANTS AND RIDER K BILL 32

(A) EB-2020-0195 + 2021 ICM vs (B) EB-2020-0195

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Heating & Water Htg.				**Heating, Water Htg. & Other Uses**			
			(A)	**(B)**	**CHANGE**		**(A)**	**(B)**	**CHANGE**	
					(A) - (B)	%			(A) - (B)	%
1.1	VOLUME	m³	3,064	3,064	0	0.0%	4,691	4,691	0	0.0%
1.2	CUSTOMER CHG.	$	257.76	257.76	0.00	0.0%	257.76	257.76	0.00	0.0%
1.3	DISTRIBUTION CHG.	$	266.01	265.86	0.15	0.1%	401.11	400.88	0.22	0.1%
1.4	LOAD BALANCING	§ $	160.40	160.40	0.00	0.0%	245.58	245.58	0.00	0.0%
1.5	SALES COMMDTY	$	322.28	322.28	0.00	0.0%	493.41	493.41	0.00	0.0%
1.6	FEDERAL CARBON CHARGE	$	179.86	179.86	0.00	0.0%	275.36	275.36	0.00	0.0%
1.7	TOTAL SALES	$	1,186.30	1,186.16	0.15	0.0%	1,673.21	1,672.99	0.22	0.0%
1.8	TOTAL T-SERVICE	$	864.03	863.88	0.15	0.0%	1,179.81	1,179.58	0.22	0.0%
1.9	SALES UNIT RATE	$/m³	0.3872	0.3871	0.0000	0.0%	0.3567	0.3566	0.0000	0.0%
1.10	T-SERVICE UNIT RATE	$/m³	0.2820	0.2819	0.0000	0.0%	0.2515	0.2515	0.0000	0.0%
1.11	SALES UNIT RATE	$/GJ	10.0774	10.0762	0.0012	0.0%	9.2839	9.2826	0.0012	0.0%
1.12	T-SERVICE UNIT RATE	$/GJ	7.3398	7.3385	0.0012	0.0%	6.5462	6.5449	0.0012	0.0%

			Heating Only				**Heating & Water Htg.**			
			(A)	**(B)**	**CHANGE**		**(A)**	**(B)**	**CHANGE**	
					(A) - (B)	%			(A) - (B)	%
2.1	VOLUME	m³	1,955	1,955	0	0.0%	2,005	2,005	0	0.0%
2.2	CUSTOMER CHG.	$	257.76	257.76	0.00	0.0%	257.76	257.76	0.00	0.0%
2.3	DISTRIBUTION CHG.	$	170.60	170.51	0.09	0.1%	177.50	177.40	0.10	0.1%
2.4	LOAD BALANCING	§ $	102.35	102.35	0.00	0.0%	104.96	104.96	0.00	0.0%
2.5	SALES COMMDTY	$	205.63	205.63	0.00	0.0%	210.89	210.89	0.00	0.0%
2.6	FEDERAL CARBON CHARGE	$	114.76	114.76	0.00	0.0%	117.69	117.69	0.00	0.0%
2.7	TOTAL SALES	$	851.10	851.00	0.09	0.0%	868.80	868.71	0.10	0.0%
2.8	TOTAL T-SERVICE	$	645.47	645.37	0.09	0.0%	657.92	657.82	0.10	0.0%
2.9	SALES UNIT RATE	$/m³	0.4353	0.4353	0.0000	0.0%	0.4333	0.4333	0.0000	0.0%
2.10	T-SERVICE UNIT RATE	$/m³	0.3302	0.3301	0.0000	0.0%	0.3281	0.3281	0.0000	0.0%
2.11	SALES UNIT RATE	$/GJ	11.3312	11.3299	0.0012	0.0%	11.2785	11.2772	0.0012	0.0%
2.12	T-SERVICE UNIT RATE	$/GJ	8.5935	8.5923	0.0012	0.0%	8.5408	8.5396	0.0012	0.0%

§ The Load Balancing Charge shown here includes proposed transportation charges

ANNUAL BILL COMPARISON - RESIDENTIAL CUSTOMERS
INCLUDING FEDERAL CARBON PRICING IMPACTS FOR NON-OBPS PARTICIPANTS AND RIDER K BILL 32

(A) EB-2020-0195 + 2021 ICM vs (B) EB-2020-0195

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Heating, Pool Htg. & Other Uses				General & Water Htg.			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
3.1	VOLUME	m³	5,048	5,048	0	0.0%	1,081	1,081	0	0.0%
3.2	CUSTOMER CHG.	$	257.76	257.76	0.00	0.0%	257.76	257.76	0.00	0.0%
3.3	DISTRIBUTION CHG.	$	431.37	431.13	0.24	0.1%	100.14	100.09	0.05	0.1%
3.4	LOAD BALANCING	§ $	264.27	264.27	0.00	0.0%	56.59	56.59	0.00	0.0%
3.5	SALES COMMDTY	$	530.96	530.96	0.00	0.0%	113.70	113.70	0.00	0.0%
	FEDERAL CARBON CHARGE	$	296.32	296.32	0.00	0.0%	63.45	63.45	0.00	0.0%
3.6	TOTAL SALES	$	1,780.67	1,780.43	0.24	0.0%	591.65	591.59	0.05	0.0%
3.7	TOTAL T-SERVICE	$	1,249.72	1,249.48	0.24	0.0%	477.95	477.89	0.05	0.0%
3.8	SALES UNIT RATE	$/m³	0.3527	0.3527	0.0000	0.0%	0.5473	0.5473	0.0000	0.0%
3.9	T-SERVICE UNIT RATE	$/m³	0.2476	0.2475	0.0000	0.0%	0.4421	0.4421	0.0000	0.0%
3.10	SALES UNIT RATE	$/GJ	9.1814	9.1801	0.0012	0.0%	14.2455	14.2443	0.0012	0.0%
3.11	T-SERVICE UNIT RATE	$/GJ	6.4437	6.4425	0.0012	0.0%	11.5079	11.5066	0.0012	0.0%

			Heating & Water Htg.				Heating & Water Htg.			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
4.1	VOLUME	m³	2,480	2,480	0	0.0%	2,400	2,400	0	0.0%
4.2	CUSTOMER CHG.	$	257.76	257.76	0.00	0.0%	257.76	257.76	0.00	0.0%
4.3	DISTRIBUTION CHG.	$	217.18	217.06	0.12	0.1%	210.22	210.11	0.11	0.1%
4.4	LOAD BALANCING	§ $	129.83	129.83	0.00	0.0%	125.64	125.64	0.00	0.0%
4.5	SALES COMMDTY	$	260.85	260.85	0.00	0.0%	252.44	252.44	0.00	0.0%
4.6	FEDERAL CARBON CHARGE	$	145.58	145.58	0.00	0.0%	140.88	140.88	0.00	0.0%
4.7	TOTAL SALES	$	1,011.19	1,011.07	0.12	0.0%	986.94	986.83	0.11	0.0%
4.8	TOTAL T-SERVICE	$	750.34	750.22	0.12	0.0%	734.51	734.39	0.11	0.0%
4.9	SALES UNIT RATE	$/m³	0.4077	0.4077	0.0000	0.0%	0.4112	0.4112	0.0000	0.0%
4.10	T-SERVICE UNIT RATE	$/m³	0.3026	0.3025	0.0000	0.0%	0.3060	0.3060	0.0000	0.0%
4.11	SALES UNIT RATE	$/GJ	10.6127	10.6114	0.0012	0.0%	10.7034	10.7022	0.0012	0.0%
4.12	T-SERVICE UNIT RATE	$/GJ	7.8750	7.8738	0.0012	0.0%	7.9658	7.9645	0.0012	0.0%

§ The Load Balancing Charge shown here includes proposed transportation charges

ANNUAL BILL COMPARISON - COMMERCIAL & INDUSTRIAL CUSTOMERS
INCLUDING FEDERAL CARBON PRICING IMPACTS FOR NON-OBPS PARTICIPANTS AND RIDER K BILL 32

(A) EB-2020-0195 + 2021 ICM vs (B) EB-2020-0195

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Commercial Heating & Other Uses				**Com. Htg., Air Cond'ng & Other Uses**			
			(A)	**(B)**	**CHANGE**		**(A)**	**(B)**	**CHANGE**	
					(A) - (B)	%			(A) - (B)	%
1.1	VOLUME	m³	22,606	22,606	0	0.0%	29,278	29,278	0	0.0%
1.2	CUSTOMER CHG.	$	872.16	872.16	0.00	0.0%	872.16	872.16	0.00	0.0%
1.3	DISTRIBUTION CHG.	$	1,557.87	1,556.89	0.97	0.1%	1,998.99	1,997.73	1.26	0.1%
1.4	LOAD BALANCING	§ $	1,166.09	1,166.09	0.00	0.0%	1,510.25	1,510.25	0.00	0.0%
1.5	SALES COMMDTY	$	2,382.66	2,382.66	0.00	0.0%	3,085.89	3,085.89	0.00	0.0%
1.6	FEDERAL CARBON CHARGE	$	1,326.97	1,326.97	0.00	0.0%	1,718.62	1,718.62	0.00	0.0%
1.7	TOTAL SALES	$	7,305.75	7,304.78	0.97	0.0%	9,185.91	9,184.65	1.26	0.0%
1.8	TOTAL T-SERVICE	$	4,923.09	4,922.12	0.97	0.0%	6,100.02	6,098.76	1.26	0.0%
1.9	SALES UNIT RATE	$/m³	0.3232	0.3231	0.0000	0.0%	0.3137	0.3137	0.0000	0.0%
1.10	T-SERVICE UNIT RATE	$/m³	0.2178	0.2177	0.0000	0.0%	0.2083	0.2083	0.0000	0.0%
1.11	SALES UNIT RATE	$/GJ	8.4117	8.4106	0.0011	0.0%	8.1663	8.1651	0.0011	0.0%
1.12	T-SERVICE UNIT RATE	$/GJ	5.6684	5.6672	0.0011	0.0%	5.4229	5.4218	0.0011	0.0%

			Medium Commercial Customer				**Large Commercial Customer**			
			(A)	**(B)**	**CHANGE**		**(A)**	**(B)**	**CHANGE**	
					(A) - (B)	%			(A) - (B)	%
2.1	VOLUME	m³	169,563	169,563	0	0.0%	339,125	339,125	0	0.0%
2.2	CUSTOMER CHG.	$	872.16	872.16	0.00	0.0%	872.16	872.16	0.00	0.0%
2.3	DISTRIBUTION CHG.	$	8,417.45	8,410.15	7.31	0.1%	15,428.53	15,413.92	14.61	0.1%
2.4	LOAD BALANCING	§ $	8,746.61	8,746.61	0.00	0.0%	17,493.17	17,493.17	0.00	0.0%
2.5	SALES COMMDTY	$	17,871.86	17,871.86	0.00	0.0%	35,743.61	35,743.61	0.00	0.0%
2.6	FEDERAL CARBON CHARGE	$	9,953.35	9,953.35	0.00	0.0%	19,906.64	19,906.64	0.00	0.0%
2.7	TOTAL SALES	$	45,861.43	45,854.12	7.31	0.0%	89,444.10	89,429.49	14.61	0.0%
2.8	TOTAL T-SERVICE	$	27,989.57	27,982.26	7.31	0.0%	53,700.49	53,685.88	14.61	0.0%
2.9	SALES UNIT RATE	$/m³	0.2705	0.2704	0.0000	0.0%	0.2637	0.2637	0.0000	0.0%
2.10	T-SERVICE UNIT RATE	$/m³	0.1651	0.1650	0.0000	0.0%	0.1584	0.1583	0.0000	0.0%
2.11	SALES UNIT RATE	$/GJ	7.0398	7.0387	0.0011	0.0%	6.8649	6.8638	0.0011	0.0%
2.12	T-SERVICE UNIT RATE	$/GJ	4.2964	4.2953	0.0011	0.0%	4.1216	4.1204	0.0011	0.0%

§ The Load Balancing Charge shown here includes proposed transportation charges

ANNUAL BILL COMPARISON - COMMERCIAL & INDUSTRIAL CUSTOMERS
INCLUDING FEDERAL CARBON PRICING IMPACTS FOR NON-OBPS PARTICIPANTS AND RIDER K BILL 32

(A) EB-2020-0195 + 2021 ICM vs (B) EB-2020-0195

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Industrial General Use				Industrial Heating & Other Uses			
			(A)	(B)	CHANGE		(A)	(B)	CHANGE	
					(A) - (B)	%			(A) - (B)	%
3.1	VOLUME	m³	43,285	43,285	0	0.0%	63,903	63,903	0	0.0%
3.2	CUSTOMER CHG.	$	872.16	872.16	0.00	0.0%	872.16	872.16	0.00	0.0%
3.3	DISTRIBUTION CHG.	$	2,763.75	2,761.88	1.87	0.1%	3,710.16	3,707.40	2.75	0.1%
3.4	LOAD BALANCING	§ $	2,232.78	2,232.78	0.00	0.0%	3,296.32	3,296.32	0.00	0.0%
3.5	SALES COMMDTY	$	4,562.22	4,562.22	0.00	0.0%	6,735.34	6,735.34	0.00	0.0%
	FEDERAL CARBON CHARGE	$	2,540.83	2,540.83	0.00	0.0%	3,751.11	3,751.11	0.00	0.0%
3.6	TOTAL SALES	$	12,971.73	12,969.87	1.87	0.0%	18,365.09	18,362.34	2.75	0.0%
3.7	TOTAL T-SERVICE	$	8,409.52	8,407.65	1.87	0.0%	11,629.75	11,626.99	2.75	0.0%
3.8	SALES UNIT RATE	$/m³	0.2997	0.2996	0.0000	0.0%	0.2874	0.2873	0.0000	0.0%
3.9	T-SERVICE UNIT RATE	$/m³	0.1943	0.1942	0.0000	0.0%	0.1820	0.1819	0.0000	0.0%
3.10	SALES UNIT RATE	$/GJ	7.8002	7.7990	0.0011	0.0%	7.4802	7.4791	0.0011	0.0%
3.11	T-SERVICE UNIT RATE	$/GJ	5.0568	5.0557	0.0011	0.0%	4.7369	4.7358	0.0011	0.0%

			Medium Industrial Customer				Large Industrial Customer			
			(A)	(B)	CHANGE		(A)	(B)	CHANGE	
					(A) - (B)	%			(A) - (B)	%
4.1	VOLUME	m³	169,563	169,563	0	0.0%	339,124	339,124	0	0.0%
4.2	CUSTOMER CHG.	$	872.16	872.16	0.00	0.0%	872.16	872.16	0.00	0.0%
4.3	DISTRIBUTION CHG.	$	8,617.50	8,610.19	7.31	0.1%	15,577.37	15,562.76	14.61	0.1%
4.4	LOAD BALANCING	§ $	8,746.61	8,746.61	0.00	0.0%	17,493.11	17,493.11	0.00	0.0%
4.5	SALES COMMDTY	$	17,871.86	17,871.86	0.00	0.0%	35,743.50	35,743.50	0.00	0.0%
4.6	FEDERAL CARBON CHARGE	$	9,953.35	9,953.35	0.00	0.0%	19,906.58	19,906.58	0.00	0.0%
4.7	TOTAL SALES	$	46,061.47	46,054.17	7.31	0.0%	89,592.73	89,578.12	14.61	0.0%
4.8	TOTAL T-SERVICE	$	28,189.62	28,182.31	7.31	0.0%	53,849.22	53,834.61	14.61	0.0%
4.9	SALES UNIT RATE	$/m³	0.2716	0.2716	0.0000	0.0%	0.2642	0.2641	0.0000	0.0%
4.10	T-SERVICE UNIT RATE	$/m³	0.1662	0.1662	0.0000	0.0%	0.1588	0.1587	0.0000	0.0%
4.11	SALES UNIT RATE	$/GJ	7.0705	7.0694	0.0011	0.0%	6.8763	6.8752	0.0011	0.0%
4.12	T-SERVICE UNIT RATE	$/GJ	4.3271	4.3260	0.0011	0.0%	4.1330	4.1319	0.0011	0.0%

§ The Load Balancing Charge shown here includes proposed transportation charges

ANNUAL BILL COMPARISON - LARGE VOLUME CUSTOMERS
INCLUDING FEDERAL CARBON PRICING IMPACTS FOR NON-OBPS PARTICIPANTS AND RIDER K BILL 32

(A) EB-2020-0195 + 2021 ICM vs (B) EB-2020-0195

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Rate 100 - Small Commercial Firm				**Rate 100 - Average Commercial Firm**			
			(A)	**(B)**	**CHANGE**		**(A)**	**(B)**	**CHANGE**	
					(A) - (B)	%			(A) - (B)	%
1.1	VOLUME	m^3	339,188	339,188	0	0.0%	598,567	598,567	0	0.0%
1.2	CUSTOMER CHG.	$	1,511.16	1,511.16	0.00	0.0%	1,511.16	1,511.16	0.00	0.0%
1.3	DISTRIBUTION CHG.	$	13,895.36	13,890.93	4.43	0.0%	67,640.27	67,618.07	22.20	0.0%
1.4	LOAD BALANCING	$	17,496.41	17,496.41	0.00	0.0%	30,876.02	30,876.02	0.00	0.0%
1.5	SALES COMMDTY	$	35,750.25	35,750.25	0.00	0.0%	63,088.67	63,088.67	0.00	0.0%
1.6	FEDERAL CARBON CHARGE	$	19,910.34	19,910.34	0.00	0.0%	35,135.88	35,135.88	0.00	0.0%
1.7	TOTAL SALES	$	88,563.51	88,559.08	4.43	0.0%	198,252.01	198,229.80	22.20	0.0%
1.8	TOTAL T-SERVICE	$	52,813.27	52,808.84	4.43	0.0%	135,163.34	135,141.13	22.20	0.0%
1.9	SALES UNIT RATE	$/m³	0.2611	0.2611	0.0000	0.0%	0.3312	0.3312	0.0000	0.0%
1.10	T-SERVICE UNIT RATE	$/m³	0.1557	0.1557	0.0000	0.0%	0.2258	0.2258	0.0000	0.0%
1.11	SALES UNIT RATE	$/GJ	6.7961	6.7957	0.0003	0.0%	8.6208	8.6198	0.0010	0.0%
1.12	T-SERVICE UNIT RATE	$/GJ	4.0527	4.0524	0.0003	0.0%	5.8774	5.8765	0.0010	0.0%

Rate 100 - Large Industrial Firm

			(A)	**(B)**	**CHANGE**	
					(A) - (B)	%
2.1	VOLUME	m^3	1,500,000	1,500,000	0	0.0%
2.2	CUSTOMER CHG.	$	1,511.16	1,511.16	0.00	0.0%
2.3	DISTRIBUTION CHG.	$	135,830.26	135,785.86	44.40	0.0%
2.4	LOAD BALANCING	$	77,374.85	77,374.85	0.00	0.0%
2.5	SALES COMMDTY	$	158,099.27	158,099.27	0.00	0.0%
2.6	FEDERAL CARBON CHARGE	$	88,050.00	88,050.00	0.00	0.0%
2.7	TOTAL SALES	$	460,865.54	460,821.14	44.40	0.0%
2.8	TOTAL T-SERVICE	$	302,766.27	302,721.87	44.40	0.0%
2.9	SALES UNIT RATE	$/m³	0.3072	0.3072	0.0000	0.0%
2.10	T-SERVICE UNIT RATE	$/m³	0.2018	0.2018	0.0000	0.0%
2.11	SALES UNIT RATE	$/GJ	7.9970	7.9962	0.0008	0.0%
2.12	T-SERVICE UNIT RATE	$/GJ	5.2536	5.2529	0.0008	0.0%

ANNUAL BILL COMPARISON - LARGE VOLUME CUSTOMERS
INCLUDING FEDERAL CARBON PRICING IMPACTS FOR NON-OBPS PARTICIPANTS AND RIDER K BILL 32

(A) EB-2020-0195 + 2021 ICM vs (B) EB-2020-0195

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Rate 145 - Small Commercial Interr.				Rate 145 - Average Commercial Interr.			
			(A)	(B)	CHANGE		(A)	(B)	CHANGE	
					(A) - (B)	%			(A) - (B)	%
3.1	VOLUME	m³	339,188	339,188	0	0.0%	598,568	598,568	0	0.0%
3.2	CUSTOMER CHG.	$	1,527.48	1,527.48	0.00	0.0%	1,527.48	1,527.48	0.00	0.0%
3.3	DISTRIBUTION CHG.	$	12,617.51	12,616.27	1.23	0.0%	19,158.49	19,156.64	1.85	0.0%
3.4	LOAD BALANCING	$	13,703.70	13,703.70	0.00	0.0%	24,183.55	24,183.55	0.00	0.0%
3.5	SALES COMMDTY	$	35,567.92	35,567.92	0.00	0.0%	62,767.01	62,767.01	0.00	0.0%
	FEDERAL CARBON CHARGE	$	19,910.34	19,910.34	0.00	0.0%	35,135.94	35,135.94	0.00	0.0%
3.6	TOTAL SALES	$	83,326.93	83,325.70	1.23	0.0%	142,772.47	142,770.63	1.85	0.0%
3.7	TOTAL T-SERVICE	$	47,759.02	47,757.79	1.23	0.0%	80,005.46	80,003.61	1.85	0.0%
3.8	SALES UNIT RATE	$/m³	0.2457	0.2457	0.0000	0.0%	0.2385	0.2385	0.0000	0.0%
3.9	T-SERVICE UNIT RATE	$/m³	0.1408	0.1408	0.0000	0.0%	0.1337	0.1337	0.0000	0.0%
3.10	SALES UNIT RATE	$/GJ	6.3942	6.3941	0.0001	0.0%	6.2083	6.2082	0.0001	0.0%
3.11	T-SERVICE UNIT RATE	$/GJ	3.6649	3.6648	0.0001	0.0%	3.4790	3.4789	0.0001	0.0%

Item No.			Rate 145 - Small Industrial Interr.				Rate 145 - Average Industrial Interr.			
			(A)	(B)	CHANGE		(A)	(B)	CHANGE	
					(A) - (B)	%			(A) - (B)	%
4.1	VOLUME	m³	339,188	339,188	0	0.0%	598,567	598,567	0	0.0%
4.2	CUSTOMER CHG.	$	1,527.48	1,527.48	0.00	0.0%	1,527.48	1,527.48	0.00	0.0%
4.3	DISTRIBUTION CHG.	$	12,893.30	12,892.07	1.23	0.0%	19,402.63	19,400.79	1.85	0.0%
4.4	LOAD BALANCING	$	13,703.70	13,703.70	0.00	0.0%	24,183.51	24,183.51	0.00	0.0%
4.5	SALES COMMDTY	$	35,567.92	35,567.92	0.00	0.0%	62,766.91	62,766.91	0.00	0.0%
4.6	FEDERAL CARBON CHARGE	$	19,910.34	19,910.34	0.00	0.0%	35,135.88	35,135.88	0.00	0.0%
4.7	TOTAL SALES	$	83,602.73	83,601.49	1.23	0.0%	143,016.41	143,014.56	1.85	0.0%
4.8	TOTAL T-SERVICE	$	48,034.81	48,033.58	1.23	0.0%	80,249.50	80,247.66	1.85	0.0%
4.9	SALES UNIT RATE	$/m³	0.2465	0.2465	0.0000	0.0%	0.2389	0.2389	0.0000	0.0%
4.10	T-SERVICE UNIT RATE	$/m³	0.1416	0.1416	0.0000	0.0%	0.1341	0.1341	0.0000	0.0%
4.11	SALES UNIT RATE	$/GJ	6.4154	6.4153	0.0001	0.0%	6.2189	6.2189	0.0001	0.0%
4.12	T-SERVICE UNIT RATE	$/GJ	3.6860	3.6859	0.0001	0.0%	3.4896	3.4895	0.0001	0.0%

ANNUAL BILL COMPARISON - LARGE VOLUME CUSTOMERS
INCLUDING FEDERAL CARBON PRICING IMPACTS FOR NON-OBPS PARTICIPANTS AND RIDER K BILL 32

(A) EB-2020-0195 + 2021 ICM vs (B) EB-2020-0195

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Rate 110 - Small Ind. Firm - 50% LF				**Rate 110 - Average Ind. Firm - 50% LF**			
			(A)	**(B)**	**CHANGE** (A) - (B)	%	**(A)**	**(B)**	**CHANGE** (A) - (B)	%
5.1	VOLUME	m³	598,568	598,568	0	0.0%	9,976,121	9,976,121	0	0.0%
5.2	CUSTOMER CHG.	$	7,229.16	7,229.16	0.00	0.0%	7,229.16	7,229.16	0.00	0.0%
5.3	DISTRIBUTION CHG.	$	14,468.19	14,458.16	10.03	0.1%	237,240.65	237,076.55	164.10	0.1%
5.4	LOAD BALANCING	$	25,817.66	25,817.66	0.00	0.0%	430,293.76	430,293.76	0.00	0.0%
5.5	SALES COMMDTY	$	62,744.94	62,744.94	0.00	0.0%	1,045,747.75	1,045,747.75	0.00	0.0%
5.6	FEDERAL CARBON CHARGE	$	35,135.94	35,135.94	0.00	0.0%	585,598.30	585,598.30	0.00	0.0%
5.7	TOTAL SALES	$	145,395.89	145,385.87	10.03	0.0%	2,306,109.63	2,305,945.53	164.10	0.0%
5.8	TOTAL T-SERVICE	$	82,650.95	82,640.92	10.03	0.0%	1,260,361.87	1,260,197.77	164.10	0.0%
5.9	SALES UNIT RATE	$/m³	0.2429	0.2429	0.0000	0.0%	0.2312	0.2311	0.0000	0.0%
5.10	T-SERVICE UNIT RATE	$/m³	0.1381	0.1381	0.0000	0.0%	0.1263	0.1263	0.0000	0.0%
5.11	SALES UNIT RATE	$/GJ	6.3224	6.3220	0.0004	0.0%	6.0167	6.0163	0.0004	0.0%
5.12	T-SERVICE UNIT RATE	$/GJ	3.5940	3.5936	0.0004	0.0%	3.2883	3.2879	0.0004	0.0%

			Rate 110 - Average Ind. Firm - 75% LF				**Rate 115 - Large Ind. Firm - 80% LF**			
			(A)	**(B)**	**CHANGE** (A) - (B)	%	**(A)**	**(B)**	**CHANGE** (A) - (B)	%
6.1	VOLUME	m³	9,976,120	9,976,120	0	0.0%	69,832,850	69,832,850	0	0.0%
6.2	CUSTOMER CHG.	$	7,229.16	7,229.16	0.00	0.0%	7,662.36	7,662.36	0.00	0.0%
6.3	DISTRIBUTION CHG.	$	188,846.48	188,735.56	110.92	0.1%	999,611.83	999,157.18	454.65	0.0%
6.4	LOAD BALANCING	$	430,293.72	430,293.72	0.00	0.0%	2,919,046.42	2,919,046.42	0.00	0.0%
6.5	SALES COMMDTY	$	1,045,747.65	1,045,747.65	0.00	0.0%	7,320,234.59	7,320,234.59	0.00	0.0%
6.6	FEDERAL CARBON CHARGE	$	585,598.24	585,598.24	0.00	0.0%	4,099,188.30	4,099,188.30	0.00	0.0%
6.7	TOTAL SALES	$	2,257,715.25	2,257,604.33	110.92	0.0%	15,345,743.50	15,345,288.85	454.65	0.0%
6.8	TOTAL T-SERVICE	$	1,211,967.60	1,211,856.68	110.92	0.0%	8,025,508.90	8,025,054.26	454.65	0.0%
6.9	SALES UNIT RATE	$/m³	0.2263	0.2263	0.0000	0.0%	0.2197	0.2197	0.0000	0.0%
6.10	T-SERVICE UNIT RATE	$/m³	0.1215	0.1215	0.0000	0.0%	0.1149	0.1149	0.0000	0.0%
6.11	SALES UNIT RATE	$/GJ	5.8905	5.8902	0.0003	0.0%	5.7197	5.7195	0.0002	0.0%
6.12	T-SERVICE UNIT RATE	$/GJ	3.1621	3.1618	0.0003	0.0%	2.9913	2.9911	0.0002	0.0%

ANNUAL BILL COMPARISON - LARGE VOLUME CUSTOMERS

INCLUDING FEDERAL CARBON PRICING IMPACTS FOR NON-OBPS PARTICIPANTS AND RIDER K BILL 32

(A) EB-2020-0195 + 2021 ICM vs (B) EB-2020-0195

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Rate 135 - Seasonal Firm				Rate 170 - Average Ind. Interr. - 50% LF			
			(A)	(B)	CHANGE		(A)	(B)	CHANGE	
					(A) - (B)	%			(A) - (B)	%
7.1	VOLUME	m³	598,567	598,567	0	0.0%	9,976,121	9,976,121	0	0.0%
7.2	CUSTOMER CHG.	$	1,426.08	1,426.08	0.00	0.0%	3,444.00	3,444.00	0.00	0.0%
7.3	DISTRIBUTION CHG.	$	11,039.16	11,038.99	0.16	0.0%	82,347.81	82,337.88	9.93	0.0%
7.4	LOAD BALANCING	$	19,470.53	19,470.53	0.00	0.0%	309,588.44	309,588.44	0.00	0.0%
7.5	SALES COMMDTY	$	62,787.75	62,787.75	0.00	0.0%	1,045,747.75	1,045,747.75	0.00	0.0%
7.6	FEDERAL CARBON CHARGE	$	35,135.88	35,135.88	0.00	0.0%	585,598.30	585,598.30	0.00	0.0%
7.7	TOTAL SALES	$	129,859.40	129,859.24	0.16	0.0%	2,026,726.30	2,026,716.37	9.93	0.0%
7.8	TOTAL T-SERVICE	$	67,071.65	67,071.49	0.16	0.0%	980,978.55	980,968.62	9.93	0.0%
7.9	SALES UNIT RATE	$/m³	0.2170	0.2170	0.0000	0.0%	0.2032	0.2032	0.0000	0.0%
7.10	T-SERVICE UNIT RATE	$/m³	0.1121	0.1121	0.0000	0.0%	0.0983	0.0983	0.0000	0.0%
7.11	SALES UNIT RATE	$/GJ	5.6468	5.6468	0.0000	0.0%	5.2878	5.2878	0.0000	0.0%
7.12	T-SERVICE UNIT RATE	$/GJ	2.9165	2.9165	0.0000	0.0%	2.5594	2.5594	0.0000	0.0%

			Rate 170 - Average Ind. Interr. - 75% LF				Rate 170 - Large Ind. Interr. - 75% LF			
			(A)	(B)	CHANGE		(A)	(B)	CHANGE	
					(A) - (B)	%			(A) - (B)	%
8.1	VOLUME	m³	9,976,120	9,976,120	0	0.0%	69,832,850	69,832,850	0	0.0%
8.2	CUSTOMER CHG.	$	3,444.00	3,444.00	0.00	0.0%	3,444.00	3,444.00	0.00	0.0%
8.3	DISTRIBUTION CHG.	$	74,958.97	74,952.26	6.71	0.0%	407,347.84	407,300.82	47.02	0.0%
8.4	LOAD BALANCING	$	309,588.41	309,588.41	0.00	0.0%	2,167,119.16	2,167,119.16	0.00	0.0%
8.5	SALES COMMDTY	$	1,045,747.64	1,045,747.64	0.00	0.0%	7,320,234.55	7,320,234.55	0.00	0.0%
8.6	FEDERAL CARBON CHARGE	$	585,598.24	585,598.24	0.00	0.0%	4,099,188.30	4,099,188.30	0.00	0.0%
8.7	TOTAL SALES	$	2,019,337.26	2,019,330.55	6.71	0.0%	13,997,333.84	13,997,286.82	47.02	0.0%
8.8	TOTAL T-SERVICE	$	973,589.62	973,582.91	6.71	0.0%	6,677,099.29	6,677,052.27	47.02	0.0%
8.9	SALES UNIT RATE	$/m³	0.2024	0.2024	0.0000	0.0%	0.2004	0.2004	0.0000	0.0%
8.1	T-SERVICE UNIT RATE	$/m³	0.0976	0.0976	0.0000	0.0%	0.0956	0.0956	0.0000	0.0%
8.11	SALES UNIT RATE	$/GJ	5.2685	5.2685	0.0000	0.0%	5.2171	5.2171	0.0000	0.0%
8.12	T-SERVICE UNIT RATE	$/GJ	2.5401	2.5401	0.0000	0.0%	2.4887	2.4887	0.0000	0.0%

ANNUAL BILL COMPARISON - RESIDENTIAL CUSTOMERS
INCLUDING FEDERAL CARBON PRICING IMPACTS FOR OBPS PARTICIPANTS AND RIDER K BILL 32

(A) EB-2020-0195 + 2021 ICM vs (B) EB-2020-0195

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Heating & Water Htg.				Heating, Water Htg. & Other Uses			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
1.1	VOLUME	m³	3,064	3,064	0	0.0%	4,691	4,691	0	0.0%
1.2	CUSTOMER CHG.	$	257.76	257.76	0.00	0.0%	257.76	257.76	0.00	0.0%
1.3	DISTRIBUTION CHG.	$	266.01	265.86	0.15	0.1%	401.11	400.88	0.22	0.1%
1.4	LOAD BALANCING	§ $	160.40	160.40	0.00	0.0%	245.58	245.58	0.00	0.0%
1.5	SALES COMMDTY	$	322.28	322.28	0.00	0.0%	493.41	493.41	0.00	0.0%
1.6	FEDERAL CARBON CHARGE	$	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
1.7	TOTAL SALES	$	1,006.45	1,006.30	0.15	0.0%	1,397.85	1,397.63	0.22	0.0%
1.8	TOTAL T-SERVICE	$	684.17	684.03	0.15	0.0%	904.45	904.22	0.22	0.0%
1.9	SALES UNIT RATE	$/m³	0.3285	0.3284	0.0000	0.0%	0.2980	0.2979	0.0000	0.0%
1.10	T-SERVICE UNIT RATE	$/m³	0.2233	0.2232	0.0000	0.0%	0.1928	0.1928	0.0000	0.0%
1.11	SALES UNIT RATE	$/GJ	8.5496	8.5483	0.0012	0.0%	7.7560	7.7548	0.0012	0.0%
1.12	T-SERVICE UNIT RATE	$/GJ	5.8119	5.8107	0.0012	0.0%	5.0183	5.0171	0.0012	0.0%

			Heating Only				Heating & Water Htg.			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
2.1	VOLUME	m³	1,955	1,955	0	0.0%	2,005	2,005	0	0.0%
2.2	CUSTOMER CHG.	$	257.76	257.76	0.00	0.0%	257.76	257.76	0.00	0.0%
2.3	DISTRIBUTION CHG.	$	170.60	170.51	0.09	0.1%	177.50	177.40	0.10	0.1%
2.4	LOAD BALANCING	§ $	102.35	102.35	0.00	0.0%	104.96	104.96	0.00	0.0%
2.5	SALES COMMDTY	$	205.63	205.63	0.00	0.0%	210.89	210.89	0.00	0.0%
2.6	FEDERAL CARBON CHARGE	$	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
2.7	TOTAL SALES	$	736.34	736.25	0.09	0.0%	751.11	751.01	0.10	0.0%
2.8	TOTAL T-SERVICE	$	530.71	530.62	0.09	0.0%	540.22	540.13	0.10	0.0%
2.9	SALES UNIT RATE	$/m³	0.3766	0.3766	0.0000	0.0%	0.3746	0.3746	0.0000	0.0%
2.10	T-SERVICE UNIT RATE	$/m³	0.2715	0.2714	0.0000	0.0%	0.2694	0.2694	0.0000	0.0%
2.11	SALES UNIT RATE	$/GJ	9.8033	9.8021	0.0012	0.0%	9.7506	9.7494	0.0012	0.0%
2.12	T-SERVICE UNIT RATE	$/GJ	7.0657	7.0644	0.0012	0.0%	7.0129	7.0117	0.0012	0.0%

§ The Load Balancing Charge shown here includes proposed transportation charges

ANNUAL BILL COMPARISON - RESIDENTIAL CUSTOMERS
INCLUDING FEDERAL CARBON PRICING IMPACTS FOR OBPS PARTICIPANTS AND RIDER K BILL 32

(A) EB-2020-0195 + 2021 ICM vs (B) EB-2020-0195

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Heating, Pool Htg. & Other Uses				General & Water Htg.			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
3.1	VOLUME	m³	5,048	5,048	0	0.0%	1,081	1,081	0	0.0%
3.2	CUSTOMER CHG.	$	257.76	257.76	0.00	0.0%	257.76	257.76	0.00	0.0%
3.3	DISTRIBUTION CHG.	$	431.37	431.13	0.24	0.1%	100.14	100.09	0.05	0.1%
3.4	LOAD BALANCING	§ $	264.27	264.27	0.00	0.0%	56.59	56.59	0.00	0.0%
3.5	SALES COMMDTY	$	530.96	530.96	0.00	0.0%	113.70	113.70	0.00	0.0%
	FEDERAL CARBON CHARGE	$	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
3.6	TOTAL SALES	$	1,484.36	1,484.11	0.24	0.0%	528.19	528.14	0.05	0.0%
3.7	TOTAL T-SERVICE	$	953.40	953.16	0.24	0.0%	414.49	414.44	0.05	0.0%
3.8	SALES UNIT RATE	$/m³	0.2940	0.2940	0.0000	0.0%	0.4886	0.4886	0.0000	0.0%
3.9	T-SERVICE UNIT RATE	$/m³	0.1889	0.1888	0.0000	0.0%	0.3834	0.3834	0.0000	0.0%
3.10	SALES UNIT RATE	$/GJ	7.6535	7.6523	0.0012	0.0%	12.7177	12.7165	0.0012	0.0%
3.11	T-SERVICE UNIT RATE	$/GJ	4.9158	4.9146	0.0012	0.0%	9.9800	9.9788	0.0012	0.0%

Item No.			Heating & Water Htg.				Heating & Water Htg.			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
4.1	VOLUME	m³	2,480	2,480	0	0.0%	2,400	2,400	0	0.0%
4.2	CUSTOMER CHG.	$	257.76	257.76	0.00	0.0%	257.76	257.76	0.00	0.0%
4.3	DISTRIBUTION CHG.	$	217.18	217.06	0.12	0.1%	210.22	210.11	0.11	0.1%
4.4	LOAD BALANCING	§ $	129.83	129.83	0.00	0.0%	125.64	125.64	0.00	0.0%
4.5	SALES COMMDTY	$	260.85	260.85	0.00	0.0%	252.44	252.44	0.00	0.0%
4.6	FEDERAL CARBON CHARGE	$	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
4.7	TOTAL SALES	$	865.62	865.50	0.12	0.0%	846.06	845.95	0.11	0.0%
4.8	TOTAL T-SERVICE	$	604.77	604.65	0.12	0.0%	593.63	593.51	0.11	0.0%
4.9	SALES UNIT RATE	$/m³	0.3490	0.3490	0.0000	0.0%	0.3525	0.3525	0.0000	0.0%
4.10	T-SERVICE UNIT RATE	$/m³	0.2439	0.2438	0.0000	0.0%	0.2473	0.2473	0.0000	0.0%
4.11	SALES UNIT RATE	$/GJ	9.0848	9.0836	0.0012	0.0%	9.1756	9.1743	0.0012	0.0%
4.12	T-SERVICE UNIT RATE	$/GJ	6.3472	6.3459	0.0012	0.0%	6.4379	6.4367	0.0012	0.0%

§ The Load Balancing Charge shown here includes proposed transportation charges

ANNUAL BILL COMPARISON - COMMERCIAL & INDUSTRIAL CUSTOMERS

INCLUDING FEDERAL CARBON PRICING IMPACTS FOR OBPS PARTICIPANTS AND RIDER K BILL 32

(A) EB-2020-0195 + 2021 ICM vs (B) EB-2020-0195

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Commercial Heating & Other Uses				Com. Htg., Air Cond'ng & Other Uses			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
1.1	VOLUME	m³	22,606	22,606	0	0.0%	29,278	29,278	0	0.0%
1.2	CUSTOMER CHG.	$	872.16	872.16	0.00	0.0%	872.16	872.16	0.00	0.0%
1.3	DISTRIBUTION CHG.	$	1,557.87	1,556.89	0.97	0.1%	1,998.99	1,997.73	1.26	0.1%
1.4	LOAD BALANCING	§ $	1,166.09	1,166.09	0.00	0.0%	1,510.25	1,510.25	0.00	0.0%
1.5	SALES COMMDTY	$	2,382.66	2,382.66	0.00	0.0%	3,085.89	3,085.89	0.00	0.0%
1.6	FEDERAL CARBON CHARGE	$	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
1.7	TOTAL SALES	$	5,978.78	5,977.81	0.97	0.0%	7,467.29	7,466.03	1.26	0.0%
1.8	TOTAL T-SERVICE	$	3,596.12	3,595.14	0.97	0.0%	4,381.40	4,380.14	1.26	0.0%
1.9	SALES UNIT RATE	$/m³	0.2645	0.2644	0.0000	0.0%	0.2550	0.2550	0.0000	0.0%
1.10	T-SERVICE UNIT RATE	$/m³	0.1591	0.1590	0.0000	0.0%	0.1496	0.1496	0.0000	0.0%
1.11	SALES UNIT RATE	$/GJ	6.8839	6.8827	0.0011	0.0%	6.6384	6.6373	0.0011	0.0%
1.12	T-SERVICE UNIT RATE	$/GJ	4.1405	4.1394	0.0011	0.0%	3.8951	3.8939	0.0011	0.0%

			Medium Commercial Customer				Large Commercial Customer			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
2.1	VOLUME	m³	169,563	169,563	0	0.0%	339,125	339,125	0	0.0%
2.2	CUSTOMER CHG.	$	872.16	872.16	0.00	0.0%	872.16	872.16	0.00	0.0%
2.3	DISTRIBUTION CHG.	$	8,417.45	8,410.15	7.31	0.1%	15,428.53	15,413.92	14.61	0.1%
2.4	LOAD BALANCING	§ $	8,746.61	8,746.61	0.00	0.0%	17,493.17	17,493.17	0.00	0.0%
2.5	SALES COMMDTY	$	17,871.86	17,871.86	0.00	0.0%	35,743.61	35,743.61	0.00	0.0%
2.6	FEDERAL CARBON CHARGE	$	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
2.7	TOTAL SALES	$	35,908.08	35,900.77	7.31	0.0%	69,537.47	69,522.85	14.61	0.0%
2.8	TOTAL T-SERVICE	$	18,036.22	18,028.92	7.31	0.0%	33,793.86	33,779.24	14.61	0.0%
2.9	SALES UNIT RATE	$/m³	0.2118	0.2117	0.0000	0.0%	0.2050	0.2050	0.0000	0.0%
2.10	T-SERVICE UNIT RATE	$/m³	0.1064	0.1063	0.0000	0.0%	0.0997	0.0996	0.0000	0.0%
2.11	SALES UNIT RATE	$/GJ	5.5119	5.5108	0.0011	0.0%	5.3371	5.3359	0.0011	0.0%
2.12	T-SERVICE UNIT RATE	$/GJ	2.7686	2.7675	0.0011	0.0%	2.5937	2.5926	0.0011	0.0%

§ The Load Balancing Charge shown here includes proposed transportation charges

ANNUAL BILL COMPARISON - COMMERCIAL & INDUSTRIAL CUSTOMERS

INCLUDING FEDERAL CARBON PRICING IMPACTS FOR OBPS PARTICIPANTS AND RIDER K BILL 32

(A) EB-2020-0195 + 2021 ICM vs (B) EB-2020-0195

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Industrial General Use				**Industrial Heating & Other Uses**			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
3.1	VOLUME	m³	43,285	43,285	0	0.0%	63,903	63,903	0	0.0%
3.2	CUSTOMER CHG.	$	872.16	872.16	0.00	0.0%	872.16	872.16	0.00	0.0%
3.3	DISTRIBUTION CHG.	$	2,763.75	2,761.88	1.87	0.1%	3,710.16	3,707.40	2.75	0.1%
3.4	LOAD BALANCING	§ $	2,232.78	2,232.78	0.00	0.0%	3,296.32	3,296.32	0.00	0.0%
3.5	SALES COMMDTY	$	4,562.22	4,562.22	0.00	0.0%	6,735.34	6,735.34	0.00	0.0%
	FEDERAL CARBON CHARGE	$	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
3.6	TOTAL SALES	$	10,430.90	10,429.04	1.87	0.0%	14,613.99	14,611.23	2.75	0.0%
3.7	TOTAL T-SERVICE	$	5,868.69	5,866.82	1.87	0.0%	7,878.64	7,875.89	2.75	0.0%
3.8	SALES UNIT RATE	$/m³	0.2410	0.2409	0.0000	0.0%	0.2287	0.2286	0.0000	0.0%
3.9	T-SERVICE UNIT RATE	$/m³	0.1356	0.1355	0.0000	0.0%	0.1233	0.1232	0.0000	0.0%
3.10	SALES UNIT RATE	$/GJ	6.2723	6.2712	0.0011	0.0%	5.9524	5.9513	0.0011	0.0%
3.11	T-SERVICE UNIT RATE	$/GJ	3.5290	3.5278	0.0011	0.0%	3.2090	3.2079	0.0011	0.0%

			Medium Industrial Customer				**Large Industrial Customer**			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
4.1	VOLUME	m³	169,563	169,563	0	0.0%	339,124	339,124	0	0.0%
4.2	CUSTOMER CHG.	$	872.16	872.16	0.00	0.0%	872.16	872.16	0.00	0.0%
4.3	DISTRIBUTION CHG.	$	8,617.50	8,610.19	7.31	0.1%	15,577.37	15,562.76	14.61	0.1%
4.4	LOAD BALANCING	§ $	8,746.61	8,746.61	0.00	0.0%	17,493.11	17,493.11	0.00	0.0%
4.5	SALES COMMDTY	$	17,871.86	17,871.86	0.00	0.0%	35,743.50	35,743.50	0.00	0.0%
4.6	FEDERAL CARBON CHARGE	$	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
4.7	TOTAL SALES	$	36,108.12	36,100.82	7.31	0.0%	69,686.15	69,671.54	14.61	0.0%
4.8	TOTAL T-SERVICE	$	18,236.27	18,228.96	7.31	0.0%	33,942.65	33,928.03	14.61	0.0%
4.9	SALES UNIT RATE	$/m³	0.2129	0.2129	0.0000	0.0%	0.2055	0.2054	0.0000	0.0%
4.10	T-SERVICE UNIT RATE	$/m³	0.1075	0.1075	0.0000	0.0%	0.1001	0.1000	0.0000	0.0%
4.11	SALES UNIT RATE	$/GJ	5.5426	5.5415	0.0011	0.0%	5.3485	5.3474	0.0011	0.0%
4.12	T-SERVICE UNIT RATE	$/GJ	2.7993	2.7982	0.0011	0.0%	2.6051	2.6040	0.0011	0.0%

§ The Load Balancing Charge shown here includes proposed transportation charges

ANNUAL BILL COMPARISON - LARGE VOLUME CUSTOMERS
INCLUDING FEDERAL CARBON PRICING IMPACTS FOR OBPS PARTICIPANTS AND RIDER K BILL 32

(A) EB-2020-0195 + 2021 ICM vs (B) EB-2020-0195

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Rate 100 - Small Commercial Firm				Rate 100 - Average Commercial Firm			
			(A)	(B)	CHANGE		(A)	(B)	CHANGE	
					(A) - (B)	%			(A) - (B)	%
1.1	VOLUME	m³	339,188	339,188	0	0.0%	598,567	598,567	0	0.0%
1.2	CUSTOMER CHG.	$	1,511.16	1,511.16	0.00	0.0%	1,511.16	1,511.16	0.00	0.0%
1.3	DISTRIBUTION CHG.	$	13,895.36	13,890.93	4.43	0.0%	67,640.27	67,618.07	22.20	0.0%
1.4	LOAD BALANCING	$	17,496.41	17,496.41	0.00	0.0%	30,876.02	30,876.02	0.00	0.0%
1.5	SALES COMMDTY	$	35,750.25	35,750.25	0.00	0.0%	63,088.67	63,088.67	0.00	0.0%
1.6	FEDERAL CARBON CHARGE	$	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
1.7	TOTAL SALES	$	68,653.18	68,648.75	4.43	0.0%	163,116.12	163,093.92	22.20	0.0%
1.8	TOTAL T-SERVICE	$	32,902.93	32,898.50	4.43	0.0%	100,027.45	100,005.25	22.20	0.0%
1.9	SALES UNIT RATE	$/m³	0.2024	0.2024	0.0000	0.0%	0.2725	0.2725	0.0000	0.0%
1.10	T-SERVICE UNIT RATE	$/m³	0.0970	0.0970	0.0000	0.0%	0.1671	0.1671	0.0000	0.0%
1.11	SALES UNIT RATE	$/GJ	5.2682	5.2679	0.0003	0.0%	7.0929	7.0920	0.0010	0.0%
1.12	T-SERVICE UNIT RATE	$/GJ	2.5249	2.5245	0.0003	0.0%	4.3496	4.3486	0.0010	0.0%

Rate 100 - Large Industrial Firm

			(A)	(B)	CHANGE	
					(A) - (B)	%
2.1	VOLUME	m³	1,500,000	1,500,000	0	0.0%
2.2	CUSTOMER CHG.	$	1,511.16	1,511.16	0.00	0.0%
2.3	DISTRIBUTION CHG.	$	135,830.26	135,785.86	44.40	0.0%
2.4	LOAD BALANCING	$	77,374.85	77,374.85	0.00	0.0%
2.5	SALES COMMDTY	$	158,099.27	158,099.27	0.00	0.0%
2.6	FEDERAL CARBON CHARGE	$	0.00	0.00	0.00	0.0%
2.7	TOTAL SALES	$	372,815.54	372,771.14	44.40	0.0%
2.8	TOTAL T-SERVICE	$	214,716.27	214,671.87	44.40	0.0%
2.9	SALES UNIT RATE	$/m³	0.2485	0.2485	0.0000	0.0%
2.10	T-SERVICE UNIT RATE	$/m³	0.1431	0.1431	0.0000	0.0%
2.11	SALES UNIT RATE	$/GJ	6.4691	6.4684	0.0008	0.0%
2.12	T-SERVICE UNIT RATE	$/GJ	3.7258	3.7250	0.0008	0.0%

ANNUAL BILL COMPARISON - LARGE VOLUME CUSTOMERS
INCLUDING FEDERAL CARBON PRICING IMPACTS FOR OBPS PARTICIPANTS AND RIDER K BILL 32

(A) EB-2020-0195 + 2021 ICM vs (B) EB-2020-0195

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Rate 145 - Small Commercial Interr.				**Rate 145 - Average Commercial Interr.**			
			(A)	**(B)**	**CHANGE** (A) - (B)	%	**(A)**	**(B)**	**CHANGE** (A) - (B)	%
3.1	VOLUME	m³	339,188	339,188	0	0.0%	598,568	598,568	0	0.0%
3.2	CUSTOMER CHG.	$	1,527.48	1,527.48	0.00	0.0%	1,527.48	1,527.48	0.00	0.0%
3.3	DISTRIBUTION CHG.	$	12,617.51	12,616.27	1.23	0.0%	19,158.49	19,156.64	1.85	0.0%
3.4	LOAD BALANCING	$	13,703.70	13,703.70	0.00	0.0%	24,183.55	24,183.55	0.00	0.0%
3.5	SALES COMMDTY	$	35,567.92	35,567.92	0.00	0.0%	62,767.01	62,767.01	0.00	0.0%
3.6	FEDERAL CARBON CHARGE	$	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
3.7	TOTAL SALES	$	63,416.60	63,415.37	1.23	0.0%	107,636.53	107,634.68	1.85	0.0%
3.8	TOTAL T-SERVICE	$	27,848.68	27,847.45	1.23	0.0%	44,869.52	44,867.67	1.85	0.0%
3.9	SALES UNIT RATE	$/m³	0.1870	0.1870	0.0000	0.0%	0.1798	0.1798	0.0000	0.0%
4.0	T-SERVICE UNIT RATE	$/m³	0.0821	0.0821	0.0000	0.0%	0.0750	0.0750	0.0000	0.0%
3.10	SALES UNIT RATE	$/GJ	4.8664	4.8663	0.0001	0.0%	4.6805	4.6804	0.0001	0.0%
3.11	T-SERVICE UNIT RATE	$/GJ	2.1370	2.1369	0.0001	0.0%	1.9511	1.9510	0.0001	0.0%

			Rate 145 - Small Industrial Interr.				**Rate 145 - Average Industrial Interr.**			
			(A)	**(B)**	**CHANGE** (A) - (B)	%	**(A)**	**(B)**	**CHANGE** (A) - (B)	%
4.1	VOLUME	m³	339,188	339,188	0	0.0%	598,567	598,567	0	0.0%
4.2	CUSTOMER CHG.	$	1,527.48	1,527.48	0.00	0.0%	1,527.48	1,527.48	0.00	0.0%
4.3	DISTRIBUTION CHG.	$	12,893.30	12,892.07	1.23	0.0%	19,402.63	19,400.79	1.85	0.0%
4.4	LOAD BALANCING	$	13,703.70	13,703.70	0.00	0.0%	24,183.51	24,183.51	0.00	0.0%
4.5	SALES COMMDTY	$	35,567.92	35,567.92	0.00	0.0%	62,766.91	62,766.91	0.00	0.0%
4.6	FEDERAL CARBON CHARGE	$	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
4.7	TOTAL SALES	$	63,692.39	63,691.16	1.23	0.0%	107,880.53	107,878.68	1.85	0.0%
4.8	TOTAL T-SERVICE	$	28,124.47	28,123.24	1.23	0.0%	45,113.62	45,111.77	1.85	0.0%
4.9	SALES UNIT RATE	$/m³	0.1878	0.1878	0.0000	0.0%	0.1802	0.1802	0.0000	0.0%
4.10	T-SERVICE UNIT RATE	$/m³	0.0829	0.0829	0.0000	0.0%	0.0754	0.0754	0.0000	0.0%
4.11	SALES UNIT RATE	$/GJ	4.8875	4.8874	0.0001	0.0%	4.6911	4.6910	0.0001	0.0%
4.12	T-SERVICE UNIT RATE	$/GJ	2.1582	2.1581	0.0001	0.0%	1.9617	1.9616	0.0001	0.0%

ANNUAL BILL COMPARISON - LARGE VOLUME CUSTOMERS
INCLUDING FEDERAL CARBON PRICING IMPACTS FOR OBPS PARTICIPANTS AND RIDER K BILL 32

(A) EB-2020-0195 + 2021 ICM vs (B) EB-2020-0195

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Rate 110 - Small Ind. Firm - 50% LF				**Rate 110 - Average Ind. Firm - 50% LF**			
			(A)	**(B)**	**CHANGE** (A) - (B)	%	**(A)**	**(B)**	**CHANGE** (A) - (B)	%
5.1	VOLUME	m³	598,568	598,568	0	0.0%	9,976,121	9,976,121	0	0.0%
5.2	CUSTOMER CHG.	$	7,229.16	7,229.16	0.00	0.0%	7,229.16	7,229.16	0.00	0.0%
5.3	DISTRIBUTION CHG.	$	14,468.19	14,458.16	10.03	0.1%	237,240.65	237,076.55	164.10	0.1%
5.4	LOAD BALANCING	$	25,817.66	25,817.66	0.00	0.0%	430,293.76	430,293.76	0.00	0.0%
5.5	SALES COMMDTY	$	62,744.94	62,744.94	0.00	0.0%	1,045,747.75	1,045,747.75	0.00	0.0%
5.6	FEDERAL CARBON CHARGE	$	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
5.7	TOTAL SALES	$	110,259.95	110,249.92	10.03	0.0%	1,720,511.33	1,720,347.22	164.10	0.0%
5.8	TOTAL T-SERVICE	$	47,515.01	47,504.98	10.03	0.0%	674,763.57	674,599.47	164.10	0.0%
5.9	SALES UNIT RATE	$/m³	0.1842	0.1842	0.0000	0.0%	0.1725	0.1724	0.0000	0.0%
5.10	T-SERVICE UNIT RATE	$/m³	0.0794	0.0794	0.0000	0.0%	0.0676	0.0676	0.0000	0.0%
5.11	SALES UNIT RATE	$/GJ	4.7945	4.7941	0.0004	0.0%	4.4889	4.4885	0.0004	0.0%
5.12	T-SERVICE UNIT RATE	$/GJ	2.0661	2.0657	0.0004	0.0%	1.7605	1.7601	0.0004	0.0%

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Rate 110 - Average Ind. Firm - 75% LF				**Rate 115 - Large Ind. Firm - 80% LF**			
			(A)	**(B)**	**CHANGE** (A) - (B)	%	**(A)**	**(B)**	**CHANGE** (A) - (B)	%
6.1	VOLUME	m³	9,976,120	9,976,120	0	0.0%	69,832,850	69,832,850	0	0.0%
6.2	CUSTOMER CHG.	$	7,229.16	7,229.16	0.00	0.0%	7,662.36	7,662.36	0.00	0.0%
6.3	DISTRIBUTION CHG.	$	188,846.48	188,735.56	110.92	0.1%	999,611.83	999,157.18	454.65	0.0%
6.4	LOAD BALANCING	$	430,293.72	430,293.72	0.00	0.0%	2,919,046.42	2,919,046.42	0.00	0.0%
6.5	SALES COMMDTY	$	1,045,747.65	1,045,747.65	0.00	0.0%	7,320,234.59	7,320,234.59	0.00	0.0%
6.6	FEDERAL CARBON CHARGE	$	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
6.7	TOTAL SALES	$	1,672,117.01	1,672,006.09	110.92	0.0%	11,246,555.20	11,246,100.55	454.65	0.0%
6.8	TOTAL T-SERVICE	$	626,369.36	626,258.44	110.92	0.0%	3,926,320.61	3,925,865.96	454.65	0.0%
6.9	SALES UNIT RATE	$/m³	0.1676	0.1676	0.0000	0.0%	0.1610	0.1610	0.0000	0.0%
6.10	T-SERVICE UNIT RATE	$/m³	0.0628	0.0628	0.0000	0.0%	0.0562	0.0562	0.0000	0.0%
6.11	SALES UNIT RATE	$/GJ	4.3626	4.3623	0.0003	0.0%	4.1918	4.1916	0.0002	0.0%
6.12	T-SERVICE UNIT RATE	$/GJ	1.6342	1.6339	0.0003	0.0%	1.4634	1.4632	0.0002	0.0%

ANNUAL BILL COMPARISON - LARGE VOLUME CUSTOMERS
INCLUDING FEDERAL CARBON PRICING IMPACTS FOR OBPS PARTICIPANTS AND RIDER K BILL 32

(A) EB-2020-0195 + 2021 ICM vs (B) EB-2020-0195

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Rate 135 - Seasonal Firm				**Rate 170 - Average Ind. Interr. - 50% LF**			
			(A)	**(B)**	**CHANGE**		**(A)**	**(B)**	**CHANGE**	
					(A) - (B)	%			(A) - (B)	%
7.1	VOLUME	m³	598,567	598,567	0	0.0%	9,976,121	9,976,121	0	0.0%
7.2	CUSTOMER CHG.	$	1,426.08	1,426.08	0.00	0.0%	3,444.00	3,444.00	0.00	0.0%
7.3	DISTRIBUTION CHG.	$	11,039.16	11,038.99	0.16	0.0%	82,347.81	82,337.88	9.93	0.0%
7.4	LOAD BALANCING	$	19,470.53	19,470.53	0.00	0.0%	309,588.44	309,588.44	0.00	0.0%
7.5	SALES COMMDTY	$	62,787.75	62,787.75	0.00	0.0%	1,045,747.75	1,045,747.75	0.00	0.0%
7.6	FEDERAL CARBON CHARGE	$	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
7.7	TOTAL SALES	$	94,723.52	94,723.35	0.16	0.0%	1,441,127.99	1,441,118.06	9.93	0.0%
7.8	TOTAL T-SERVICE	$	31,935.77	31,935.61	0.16	0.0%	395,380.25	395,370.32	9.93	0.0%
7.9	SALES UNIT RATE	$/m³	0.1583	0.1583	0.0000	0.0%	0.1445	0.1445	0.0000	0.0%
7.10	T-SERVICE UNIT RATE	$/m³	0.0534	0.0534	0.0000	0.0%	0.0396	0.0396	0.0000	0.0%
7.11	SALES UNIT RATE	$/GJ	4.1190	4.1190	0.0000	0.0%	3.7600	3.7599	0.0000	0.0%
7.12	T-SERVICE UNIT RATE	$/GJ	1.3887	1.3887	0.0000	0.0%	1.0316	1.0315	0.0000	0.0%

			Rate 170 - Average Ind. Interr. - 75% LF				**Rate 170 - Large Ind. Interr. - 75% LF**			
			(A)	**(B)**	**CHANGE**		**(A)**	**(B)**	**CHANGE**	
					(A) - (B)	%			(A) - (B)	%
8.1	VOLUME	m³	9,976,120	9,976,120	0	0.0%	69,832,850	69,832,850	0	0.0%
8.2	CUSTOMER CHG.	$	3,444.00	3,444.00	0.00	0.0%	3,444.00	3,444.00	0.00	0.0%
8.3	DISTRIBUTION CHG.	$	74,958.97	74,952.26	6.71	0.0%	407,347.84	407,300.82	47.02	0.0%
8.4	LOAD BALANCING	$	309,588.41	309,588.41	0.00	0.0%	2,167,119.16	2,167,119.16	0.00	0.0%
8.5	SALES COMMDTY	$	1,045,747.64	1,045,747.64	0.00	0.0%	7,320,234.55	7,320,234.55	0.00	0.0%
8.6	FEDERAL CARBON CHARGE	$	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
8.7	TOTAL SALES	$	1,433,739.02	1,433,732.31	6.71	0.0%	9,898,145.55	9,898,098.53	47.02	0.0%
8.8	TOTAL T-SERVICE	$	387,991.38	387,984.66	6.71	0.0%	2,577,911.00	2,577,863.98	47.02	0.0%
8.9	SALES UNIT RATE	$/m³	0.1437	0.1437	0.0000	0.0%	0.1417	0.1417	0.0000	0.0%
8.1	T-SERVICE UNIT RATE	$/m³	0.0389	0.0389	0.0000	0.0%	0.0369	0.0369	0.0000	0.0%
8.11	SALES UNIT RATE	$/GJ	3.7407	3.7407	0.0000	0.0%	3.6892	3.6892	0.0000	0.0%
8.12	T-SERVICE UNIT RATE	$/GJ	1.0123	1.0123	0.0000	0.0%	0.9608	0.9608	0.0000	0.0%

UNION RATE ZONES
Calculation of 2021 ICM Bill Impacts
Sales Service and Direct Purchase Bill Impacts for Typical Small and Large Customers

Line No.	Particulars	Approved - EB-2020-0095 (1) Total Bill ($) (a)	Approved - EB-2020-0095 (1) Unit Rate (cents/m^3) (b)	Proposed - EB-2020-0181 with ICM Total Bill ($) (c)	Proposed - EB-2020-0181 with ICM Unit Rate (cents/m^3) (d)	Total Bill Change ($) (e) = (c - a)	Bill Impact Including Federal Carbon Charge (%) (f) = (e / a)	Bill Impact Excluding Federal Carbon Charge (%) (g)
	Small Rate 01							
1	Delivery Charges	486	22.0823	486	22.0823	-	0.0%	0.0%
2	Federal Carbon Charge	129	5.8700	129	5.8700	-	0.0%	0.0%
3	Gas Supply Charges (2)	434	19.7355	434	19.7355	-	0.0%	0.0%
4	Total Bill	1,049	47.6877	1,049	47.6877	-	0.0%	0.0%
5	Sales Service Impact					-	0.0%	0.0%
6	Bundled-T (Direct Purchase) Impact					-	0.0%	0.0%
	Small Rate 10							
7	Delivery Charges	5,173	8.6223	5,173	8.6223	-	0.0%	0.0%
8	Federal Carbon Charge	3,522	5.8700	3,522	5.8700	-	0.0%	0.0%
9	Gas Supply Charges (2)	10,798	17.9968	10,798	17.9968	-	0.0%	0.0%
10	Total Bill	19,493	32.4891	19,493	32.4891	-	0.0%	0.0%
11	Sales Service Impact					-	0.0%	0.0%
12	Bundled-T (Direct Purchase) Impact					-	0.0%	0.0%
	Large Rate 10							
13	Delivery Charges	16,853	6.7411	16,853	6.7411	-	0.0%	0.0%
14	Federal Carbon Charge	14,675	5.8700	14,675	5.8700	-	0.0%	0.0%
15	Gas Supply Charges (2)	44,992	17.9968	44,992	17.9968	-	0.0%	0.0%
16	Total Bill	76,520	30.6079	76,520	30.6079	-	0.0%	0.0%
17	Sales Service Impact					-	0.0%	0.0%
18	Bundled-T (Direct Purchase) Impact					-	0.0%	0.0%
	Small Rate 20							
19	Delivery Charges	90,209	3.0070	90,209	3.0070	-	0.0%	0.0%
20	Federal Carbon Charge	176,100	5.8700	176,100	5.8700	-	0.0%	0.0%
21	Gas Supply Charges (2)	434,137	14.4712	434,137	14.4712	-	0.0%	0.0%
22	Total Bill	700,447	23.3482	700,447	23.3482	-	0.0%	0.0%
23	Sales Service Impact					-	0.0%	0.0%
24	Bundled-T (Direct Purchase) Impact					-	0.0%	0.0%
	Large Rate 20							
25	Delivery Charges	352,156	2.3477	352,156	2.3477	-	0.0%	0.0%
26	Federal Carbon Charge	880,500	5.8700	880,500	5.8700	-	0.0%	0.0%
27	Gas Supply Charges (2)	2,121,246	14.1416	2,121,246	14.1416	-	0.0%	0.0%
28	Total Bill	3,353,902	22.3593	3,353,902	22.3593	-	0.0%	0.0%
29	Sales Service Impact					-	0.0%	0.0%
30	Bundled-T (Direct Purchase) Impact					-	0.0%	0.0%
	Average Rate 25							
31	Delivery Charges	74,392	3.2700	74,392	3.2700	-	0.0%	0.0%
32	Federal Carbon Charge	133,543	5.8700	133,543	5.8700	-	0.0%	0.0%
33	Gas Supply Charges (2)	300,628	13.2144	300,628	13.2144	-	0.0%	0.0%
34	Total Bill	508,562	22.3544	508,562	22.3544	-	0.0%	0.0%
35	Sales Service Impact					-	0.0%	0.0%
36	T-Service (Direct Purchase) Impact					-	0.0%	0.0%
	Small Rate 100							
37	Delivery Charges	322,121	1.1930	322,121	1.1930	-	0.0%	0.0%
38	Federal Carbon Charge	1,584,900	5.8700	1,584,900	5.8700	-	0.0%	0.0%
39	Gas Supply Charges (2)	4,860,393	18.0015	4,860,393	18.0015	-	0.0%	0.0%
40	Total Bill	6,767,414	25.0645	6,767,414	25.0645	-	0.0%	0.0%
41	Sales Service Impact					-	0.0%	0.0%
42	T-Service (Direct Purchase) Impact					-	0.0%	0.0%
	Large Rate 100							
43	Delivery Charges	2,630,588	1.0961	2,630,588	1.0961	-	0.0%	0.0%
44	Federal Carbon Charge	14,088,000	5.8700	14,088,000	5.8700	-	0.0%	0.0%
45	Gas Supply Charges (2)	42,590,563	17.7461	42,590,563	17.7461	-	0.0%	0.0%
46	Total Bill	59,309,151	24.7121	59,309,151	24.7121	-	0.0%	0.0%
47	Sales Service Impact					-	0.0%	0.0%
48	T-Service (Direct Purchase) Impact					-	0.0%	0.0%

Notes:
(1) EB-2020-0095 Settlement Agreement filed October 6, 2020, Exhibit D, Tab 2, Rate Order, Working Papers, Schedule 4.
(2) Gas Supply charges based on Union North East Zone.

UNION RATE ZONES
Calculation of 2021 ICM Bill Impacts
Sales Service and Direct Purchase Bill Impacts for Typical Small and Large Customers

		Approved - EB-2020-0095 (1)		Proposed - EB-2020-0181 with ICM			Bill Impact	
Line No.	Particulars	Total Bill ($)	Unit Rate (cents/m^3)	Total Bill ($)	Unit Rate (cents/m^3)	Total Bill Change ($)	Including Federal Carbon Charge (%)	Excluding Federal Carbon Charge (%)
		(a)	(b)	(c)	(d)	(e) = (c - a)	(f) = (e / a)	(g)
	Small Rate M1							
1	Delivery Charges	411	18.6659	413	18.7891	2.71	0.7%	0.7%
2	Federal Carbon Charge	129	5.8700	129	5.8700	-	0.0%	0.0%
3	Gas Supply Charges	271	12.3205	271	12.3205	-	0.0%	0.0%
4	Total Bill	811	36.8559	814	36.9791	2.71	0.3%	0.4%
5	Sales Service Impact					2.71	0.3%	0.4%
6	Direct Purchase Impact					2.71	0.5%	0.7%
	Small Rate M2							
7	Delivery Charges	4,300	7.1663	4,366	7.2766	66	1.5%	1.5%
8	Federal Carbon Charge	3,522	5.8700	3,522	5.8700	-	0.0%	0.0%
9	Gas Supply Charges	7,392	12.3205	7,392	12.3205	-	0.0%	0.0%
10	Total Bill	15,214	25.3568	15,280	25.4671	66	0.4%	0.6%
11	Sales Service Impact					66	0.4%	0.6%
12	Direct Purchase Impact					66	0.8%	1.5%
	Large Rate M2							
13	Delivery Charges	14,421	5.7682	14,696	5.8785	276	1.9%	1.9%
14	Federal Carbon Charge	14,675	5.8700	14,675	5.8700	-	0.0%	0.0%
15	Gas Supply Charges	30,801	12.3205	30,801	12.3205	-	0.0%	0.0%
16	Total Bill	59,897	23.9587	60,173	24.0690	276	0.5%	0.6%
17	Sales Service Impact					276	0.5%	0.6%
18	Direct Purchase Impact					276	0.9%	1.9%
	Small Rate M4							
19	Delivery Charges	51,584	5.8953	52,249	5.9713	665	1.3%	1.3%
20	Federal Carbon Charge	51,363	5.8700	51,363	5.8700	-	0.0%	0.0%
21	Gas Supply Charges	107,804	12.3205	107,804	12.3205	-	0.0%	0.0%
22	Total Bill	210,751	24.0858	211,416	24.1618	665	0.3%	0.4%
23	Sales Service Impact					665	0.3%	0.4%
24	Direct Purchase Impact					665	0.6%	1.3%
	Large Rate M4							
25	Delivery Charges	402,005	3.3500	408,928	3.4077	6,923	1.7%	1.7%
26	Federal Carbon Charge	704,400	5.8700	704,400	5.8700	-	0.0%	0.0%
27	Gas Supply Charges	1,478,460	12.3205	1,478,460	12.3205	-	0.0%	0.0%
28	Total Bill	2,584,865	21.5405	2,591,788	21.5982	6,923	0.3%	0.4%
29	Sales Service Impact					6,923	0.3%	0.4%
30	Direct Purchase Impact					6,923	0.6%	1.7%
	Small Rate M5							
31	Delivery Charges	34,806	4.2189	35,275	4.2757	469	1.3%	1.3%
32	Federal Carbon Charge	48,428	5.8700	48,428	5.8700	-	0.0%	0.0%
33	Gas Supply Charges	101,644	12.3205	101,644	12.3205	-	0.0%	0.0%
34	Total Bill	184,878	22.4094	185,346	22.4662	469	0.3%	0.3%
35	Sales Service Impact					469	0.3%	0.3%
36	Direct Purchase Impact					469	0.6%	1.3%
	Large Rate M5							
37	Delivery Charges	199,428	3.0681	203,120	3.1249	3,692	1.9%	1.9%
38	Federal Carbon Charge	381,550	5.8700	381,550	5.8700	-	0.0%	0.0%
39	Gas Supply Charges	800,833	12.3205	800,833	12.3205	-	0.0%	0.0%
40	Total Bill	1,381,810	21.2586	1,385,502	21.3154	3,692	0.3%	0.4%
41	Sales Service Impact					3,692	0.3%	0.4%
42	Direct Purchase Impact					3,692	0.6%	1.9%
	Small Rate M7							
43	Delivery Charges	766,608	2.1295	784,450	2.1790	17,842	2.3%	2.3%
44	Federal Carbon Charge	2,113,200	5.8700	2,113,200	5.8700	-	0.0%	0.0%
45	Gas Supply Charges	4,435,380	12.3205	4,435,380	12.3205	-	0.0%	0.0%
46	Total Bill	7,315,188	20.3200	7,333,030	20.3695	17,842	0.2%	0.3%
47	Sales Service Impact					17,842	0.2%	0.3%
48	Direct Purchase Impact					17,842	0.6%	2.3%
	Large Rate M7							
49	Delivery Charges	3,072,488	5.9086	3,150,343	6.0584	77,855	2.5%	2.5%
50	Federal Carbon Charge	3,052,400	5.8700	3,052,400	5.8700	-	0.0%	0.0%
51	Gas Supply Charges	6,406,660	12.3205	6,406,660	12.3205	-	0.0%	0.0%
52	Total Bill	12,531,548	24.0991	12,609,403	24.2489	77,855	0.6%	0.8%
53	Sales Service Impact					77,855	0.6%	0.8%
54	Direct Purchase Impact					77,855	1.3%	2.5%

Notes:
(1) EB-2020-0095 Settlement Agreement filed October 6, 2020, Exhibit D, Tab 2, Rate Order, Working Papers, Schedule 4.

UNION RATE ZONES
Calculation of 2021 ICM Bill Impacts
Sales Service and Direct Purchase Bill Impacts for Typical Small and Large Customers

		Approved - EB-2020-0095 (1)		Proposed - EB-2020-0181 with ICM			Bill Impact	
Line No.	Particulars	Total Bill ($)	Unit Rate (cents/m^3)	Total Bill ($)	Unit Rate (cents/m^3)	Total Bill Change ($)	Including Federal Carbon Charge (%)	Excluding Federal Carbon Charge (%)
		(a)	(b)	(c)	(d)	(e) = (c - a)	(f) = (e / a)	(g)
	Small Rate M9							
1	Delivery Charges	181,783	2.6156	182,759	2.6296	977		0.5%
2	Gas Supply Charges	856,275	12.3205	856,275	12.3205	-		0.0%
3	Total Bill	1,038,058	14.9361	1,039,034	14.9501	977		0.1%
4	Sales Service Impact					977		0.1%
5	Direct Purchase Impact					977		0.5%
	Large Rate M9							
6	Delivery Charges	540,647	2.6794	543,556	2.6938	2,909		0.5%
7	Gas Supply Charges	2,486,030	12.3205	2,486,030	12.3205	-		0.0%
8	Total Bill	3,026,677	14.9999	3,029,586	15.0143	2,909		0.1%
9	Sales Service Impact					2,909		0.1%
10	Direct Purchase Impact					2,909		0.5%
	Average Rate M10							
11	Delivery Charges	7,342	7.7688	7,359	7.7874	18		0.2%
12	Gas Supply Charges	11,643	12.3205	11,643	12.3205	-		0.0%
13	Total Bill	18,984	20.0893	19,002	20.1079	18		0.1%
14	Sales Service Impact					18		0.1%
15	Direct Purchase Impact					18		0.2%
	Small Rate T1							
16	Delivery Charges	165,220	2.1921	168,330	2.2334	3,110	1.9%	1.9%
17	Federal Carbon Charge	442,422	5.8700	442,422	5.8700	-	0.0%	0.0%
18	Gas Supply Charges	928,596	12.3205	928,596	12.3205	-	0.0%	0.0%
19	Total Bill	1,536,238	20.3826	1,539,348	20.4239	3,110	0.2%	0.3%
20	Sales Service Impact					3,110	0.2%	0.3%
21	Direct Purchase Impact					3,110	0.5%	1.9%
	Average Rate T1							
22	Delivery Charges	256,683	2.2193	262,571	2.2702	5,888	2.3%	2.3%
23	Federal Carbon Charge	678,921	5.8700	678,921	5.8700	-	0.0%	0.0%
24	Gas Supply Charges	1,424,981	12.3205	1,424,981	12.3205	-	0.0%	0.0%
25	Total Bill	2,360,585	20.4098	2,366,473	20.4607	5,888	0.2%	0.4%
26	Sales Service Impact					5,888	0.2%	0.4%
27	Direct Purchase Impact					5,888	0.6%	2.3%
	Large Rate T1							
28	Delivery Charges	577,642	2.2543	593,706	2.3170	16,064	2.8%	2.8%
29	Federal Carbon Charge	1,504,133	5.8700	1,504,133	5.8700	-	0.0%	0.0%
30	Gas Supply Charges	3,157,015	12.3205	3,157,015	12.3205	-	0.0%	0.0%
31	Total Bill	5,238,790	20.4448	5,254,854	20.5075	16,064	0.3%	0.4%
32	Sales Service Impact					16,064	0.3%	0.4%
33	Direct Purchase Impact					16,064	0.8%	2.8%
	Small Rate T2							
34	Delivery Charges	737,331	1.2443	744,143	1.2558	6,813	0.9%	0.9%
35	Federal Carbon Charge	3,478,327	5.8700	3,478,327	5.8700	-	0.0%	0.0%
36	Gas Supply Charges	7,300,635	12.3205	7,300,635	12.3205	-	0.0%	0.0%
37	Total Bill	11,516,293	19.4348	11,523,106	19.4463	6,813	0.1%	0.1%
38	Sales Service Impact					6,813	0.1%	0.1%
39	Direct Purchase Impact					6,813	0.2%	0.9%
	Average Rate T2							
40	Delivery Charges	1,781,985	0.9009	1,805,972	0.9131	23,988	1.3%	1.3%
41	Federal Carbon Charge	11,610,264	5.8700	11,610,264	5.8700	-	0.0%	0.0%
42	Gas Supply Charges	24,368,698	12.3205	24,368,698	12.3205	-	0.0%	0.0%
43	Total Bill	37,760,947	19.0914	37,784,935	19.1036	23,988	0.1%	0.1%
44	Sales Service Impact					23,988	0.1%	0.1%
45	Direct Purchase Impact					23,988	0.2%	1.3%
	Large Rate T2							
46	Delivery Charges	2,945,626	0.7959	2,988,653	0.8075	43,027	1.5%	1.5%
47	Federal Carbon Charge	21,724,224	5.8700	21,724,224	5.8700	-	0.0%	0.0%
48	Gas Supply Charges	45,596,815	12.3205	45,596,815	12.3205	-	0.0%	0.0%
49	Total Bill	70,266,666	18.9864	70,309,693	18.9980	43,027	0.1%	0.1%
50	Sales Service Impact					43,027	0.1%	0.1%
51	Direct Purchase Impact					43,027	0.2%	1.5%
	Large Rate T3							
52	Delivery Charges	5,699,774	2.0900	5,739,338	2.1045	39,565		0.7%
53	Gas Supply Charges	33,599,482	12.3205	33,599,482	12.3205	-		0.0%
54	Total Bill	39,299,256	14.4105	39,338,820	14.4250	39,565		0.1%
55	Sales Service Impact					39,565		0.1%
56	Direct Purchase Impact					39,565		0.7%

Notes:
(1) EB-2020-0095 Settlement Agreement filed October 6, 2020, Exhibit D, Tab 2, Rate Order, Working Papers, Schedule 4.

ENBRIDGE GAS INC.

UTILITY SYSTEM PLAN

CONTENTS

1.0 INTRODUCTION

1.1 PURPOSE

1. This is Enbridge Gas Utility System Plan ("USP") covering the 2021 to 2025 period which describes how the company plans to drive operational effectiveness through strong asset management and meet the expectations set out in the OEB's Renewed Regulatory Framework ("RRF").

2. In the MAADs Decision, the OEB expected the Company to file a consolidated USP for any Incremental Capital Module ("ICM") request for 2021 rates and beyond.[1] In line with the OEB's decision, Enbridge Gas has worked diligently to provide a consolidated USP for this 2021 rate application with a consolidated Asset Management Plan ("AMP") and a Customer Engagement Study to inform Enbridge Gas's Asset Plan. The AMP and the Customer Engagement Study are filed at Exhibit C, Tab 2, Schedule 1 and Exhibit C, Tab 3, Schedule 1 respectively in this application.

[1] EB-2017-0306/EB-2017-0307 Decision and Order, August 30, 2018, pp. 33-34.

3. Strong asset management that balances risk, cost and performance, while delivering value to customers has been at the core of Enbridge Gas's business for years and is demonstrated throughout the USP and AMP.

4. Enbridge Gas's USP meets the needs of the utility's customers of the EGD and Union rate zones through strong asset management that supports the delivery of safe, reliable service.

1.2 OEB FILING REQUIREMENTS

5. On February 16, 2017, the OEB issued amended filing requirements for natural gas rate applications, the OEB Filing Requirements for Natural Gas Rate Applications (the "Gas Filing Requirements"). Section 2.2.6 of the Gas Filing Requirements provides the requirements for a USP. As discussed above, in the MAADs Decision, the OEB expected Enbridge Gas to file a consolidated USP in support of the 2021 rate application. Enbridge Gas's USP fulfills the requirements in Section 2.2.6. In addition to the Gas Filing Requirements, there are several other OEB policies which were referred to in the creation of Enbridge Gas's USP. These include elements from:

- The October 13, 2016 *Handbook for Utility Rate Applications* (the "Rate Handbook");

- the Report of the Board, Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach (the "RRFE Report"), which is applicable to all rate regulated utilities;
- the OEB's guidelines for natural gas utilities' transportation and distribution system projects (EBO 134 and EBO. 188)[2]; and
- Chapter 5 of the *Filing Requirements for Electricity Distributor Applications*[3], which provides further guidance from the OEB on components of a Distribution System Plan, which is informative to certain components of the USP.

6. A key component of Enbridge Gas's USP is demonstrating to the OEB and stakeholders how the objectives of the RRF have been met through a principled asset management approach. Specifically, how the USP drives an outcome-based approach to asset management.

1.3 ENBRIDGE GAS'S SYSTEM OVERVIEW

7. Enbridge Gas's values of integrity, safety and respect, along with its strategic priorities, guide decision making in the Company. Asset management provides the necessary structure to make informed asset decisions and execute the resulting actions, as aligned with the RRF framework.

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[2] Gas Filing Requirements, February 16, 2017, p. 21.
[3] Filing Requirements For Electricity Distribution Rate Applications - 2018 Edition for 2019 Rate Applications - Chapter 5 Consolidated Distribution System Plan, July 12, 2018.

8. Enbridge Gas's strategic priorities and alignment with the RRF are shown in Table 1.

Table 1
Enbridge Gas Strategic Priorities

Strategic Priority	RRF Outcome	Description
1. Safety and Operational Reliability	Customer Focus and Operational Effectiveness	Ensuring the safety of communities, and preventing harm to the public, employees, and the environment is Enbridge Gas's highest duty. Every injury and incident can be prevented, and every employee has a responsibility to act in accordance with that duty. Safety information for Enbridge Gas customers, contractors and the communities in which we operate can be found on the Company's safety pages.
2. Optimize the Base Business	Customer Focus, Operational Effectiveness and Financial Performance	The integration of Enbridge Gas drives efficiencies, including economies of scale as well as continuous improvement through the adoption of best practices. These efficiencies provide benefits to both customers and the Company. The integration also provides an opportunity for greater strategic focus and a stronger platform to face the challenges and opportunities in the Ontario Energy Sector.
3. Execute the Capital Program	Operational Effectiveness, Customer Focus, Financial Performance	Project execution is integral to provide customers with access to a cost effective and reliable energy source. Execution of the Company's Asset Management Plan ensures that a safe and reliable

Strategic Priority	RRF Outcome	Description
		distribution system is maintained to satisfy customers energy needs. Forecasting a long term asset investment plan and ensuring money is spent on the right things at the right time helps to ensure the distribution system is maintained in the most cost effective way. It is therefore, a critical priority for the Company to engage proactively with communities and customers to understand customer preferences and changes in demand to support the development of a plan that will ensure safe and reliable access to natural gas. Aligning roles and organization structure to support Asset Management enables the entire company to remain integrated with the execution of the Asset Management program and the resultant capital plan.
4. Extend Growth	Customer Focus, Operational Effectiveness and Financial Performance	Enbridge Gas expects customer growth to remain strong, driven by Ontario population growth and demand for natural gas as a cost effective source of energy. Enbridge Gas also receives expansion requests to help bring natural gas to remote locations, including Indigenous communities. A strong Asset Management program allows for value-based decision making, where optimizing/prioritizing is based on risk and opportunity.

Strategic Priority	RRF Outcome	Description
5.Maintain Financial Strength and Flexibility, and Disciplined Capital Allocation	Financial Performance	Enbridge Gas is committed to ensuring the proper governance structure and management oversight to enable the Company to invest capital in the most efficient and effective way to meet the Company's obligations, ensure safety, and maximize the value of investments. It also enables the business to plan and execute work in a timely fashion with minimal administrative burden, responding quickly to the demands of the customers that the Company serves.
6. Adapt to Energy Transition Over Time	Public Policy Responsiveness	Enbridge Gas is committed to being part of the transition to a lower carbon economy. Examples of this include support for programs such as Renewable Natural Gas, Compressed Natural Gas, and the integration of gas and electric infrastructures using technology like combined heat and power, geothermal loops and hydrogen storage and blending.

9. Enbridge Gas has over $24 billion in assets and serves over 3.7 million residential, commercial, and industrial customers in Ontario delivering heating to more than 73% of Ontario's homes. Enbridge Gas's service area is divided into the following seven operating regions:

- Northern Region covers the legacy Union Eastern, Northwest, and Northeast districts

- Eastern Region covers Ottawa and the surrounding area
- Southwest Region covers the Windsor/Chatham and the Sarnia/London areas
- Southeast Region covers the Waterloo/Brantford and the Halton/Hamilton areas
- GTA West & Niagara Region covers the western Greater Toronto Area (GTA) and Niagara
- GTA East Region covers the eastern Greater Toronto Area
- Toronto Region covers the city of Toronto

10. Enbridge Gas has storage and transmission assets that serve to receive, store, and transport natural gas for markets in Ontario, Québec and the U.S. Northeast. Enbridge Gas's Dawn Hub in southwestern Ontario is connected to most of North America's major natural gas basins, including abundant and affordable gas supplies in the Utica and Marcellus producing regions. It is similarly connected to the major demand markets. Like spokes of a wheel, more than half a dozen major pipelines connect at Dawn. Enbridge Gas transports gas from the Dawn Hub to the GTA through its West, Central, and East transmission operations areas.

11. Enbridge Gas owns and operates over 83,000 kilometres ("km") of pipelines (mains) for the transportation and distribution of gas, plus service pipes to transfer gas to meters on customer premises. In addition, Enbridge Gas owns and

operates approximately 312.7 PJ underground gas storage facilities (199.4 PJ regulated & about 113.3 PJ unregulated), has more than 800,000 horsepower of compression and one liquified natural gas facility. Enbridge Gas's supporting assets include service facilities, fleet, and information technology assets. The fleet assets include 1895 fleet vehicles, plus heavy equipment and tools. Enbridge Gas has 92 buildings across Ontario including administration sites, and operations depots to support functional business needs and activities. The information technology assets include over 300 applications plus associated software and hardware that provide critical functionality to effectively run the business.

2.0 Economic and Planning Assumptions

2.1 Current Budget Cycle Assumptions

12. Enbridge Gas completes an annual budget and multi-year long range planning ("LRP") process, which reflects a forecast of customer demands, revenues, operating costs and capital investments. This process is underpinned by key economic and planning assumptions. These assumptions are obtained from both internal and external sources and are reviewed and approved by management.

13. The key assumptions and sources of information are detailed below:

i. Revenue inflation: The revenue escalator is determined by a price cap index ("PCI"), where PCI growth is driven by an inflation factor using GDP IPI FDD, less a productivity factor of zero and a stretch factor of 0.30% (the "X factor"). This is determined in accordance with the 2019-2023 IRM framework as approved in the MAADs Decision[4].

ii. Labour escalation: This assumption is determined by the corporate compensation function and is applied to non-unionized salary and wage costs. Unionized wages are escalated in accordance with the respective collective agreements in place;

iii. Non-wage inflation: This assumption is determined by the corporate planning and forecast function and is applied to non-wage operating and maintenance costs;

iv. Foreign exchange and interest rates: These financial indicators are issued from the corporate treasury function and are based on the average of forecasts from external sources and historical differentials;

v. Annual demand: Is based on the weather normalized demand forecast for general service and contract market rate classes. The annual demand forecasts are prepared separately for the EGD and Union rate zones, using legacy OEB-approved methodologies and criteria. It is based on multiple

[4] EB-2017-0306/EB-2017-0307 Decision and Order, August 30, 2018

regression analyses and includes several variables including weather normal, energy efficiency, price signals and macroeconomic indicators;

vi. Customer Attachments: The forecast for customer growth includes new housing starts, residential conversions, commercial customer additions and industrial additions. This forecast is based on historical customer counts as well as external housing forecasts combined with market share and natural gas penetration rates. Known projects are also included.

14. The key assumptions are reviewed and approved by management and distributed to the relevant forecasting and planning function to incorporate into the relevant budget and LRP process, as detailed in Section 3.

2.2 Expectations of Natural Gas Prices

15. Growth in the natural gas storage and transmission business is driven by economic factors such as exchange rates, interest rates and gross domestic product, but the primary driver relates to changing North American natural gas market fundamentals such as supply and demand, natural gas prices, natural gas basis differentials (price differential between locations) with infrastructure projects providing access to growing supply basins and demand centres.

16. The major contributing factor to Enbridge Gas's recent infrastructure expansions relates to the growth in natural gas production from the Marcellus and Utica shale basins which are within 300 km of Ontario and shippers that are accessing the Dawn Hub. As a result, shippers in Ontario, Quebec, Eastern Canada, and the U.S. Northeast have been adjusting their natural gas supply portfolios seeking diversity and security of supply as well as cost-competitive supply through further access to the Dawn Hub.

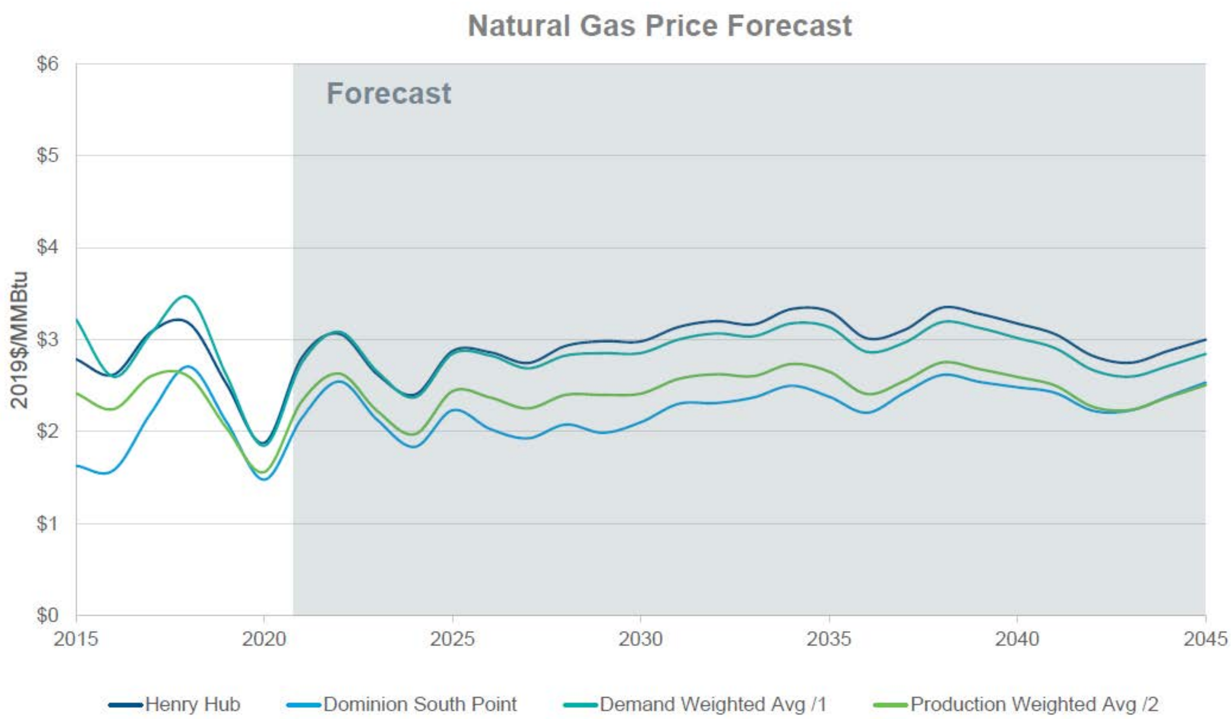
17. Although difficult to forecast, going forward Enbridge Gas expects further growth along the Dawn Parkway System driven by further demand growth in the U.S. Northeast, Quebec, Eastern Canada and Ontario Local Distribution Companies ("LDCs").

Natural Gas Price Signals

18. The emergence of shale production has increased dramatically since 2007 and the increase in available supply has put downward pressure on natural gas prices across North America during this timeframe. Continued development of the Marcellus and Utica plays in the U.S. Northeast is the main driver of supply growth in total U.S. shale gas production.

19. Natural gas prices remain low relative to historic averages. Natural gas prices set at Henry Hub are generally seen to be the primary price for the North American natural gas market with locational basis differentials based off the New York Mercantile Exchange ("NYMEX"). ICF forecasts that Henry Hub prices will remain between $1.88 and $3.35 USD/MMBtu in the longer term as shown in Figure 1.

Figure 1



"Source: ICF Forecast: Natural Gas – Strategic, Q3 2020 Outlook. Used with permission"

3.0 COMPANY BUDGET AND LONG RANGE PLANNING PROCESS

3.1 OVERVIEW

20. Each year Enbridge Gas completes an annual budget and multi-year LRP process. This process reflects Enbridge Gas's forecast of customer demands, revenues, operating costs, and capital investments. The budget and LRP allows the company to earn an appropriate level of shareholder return and monitor its financial viability in support of maintaining safe and reliable operations.

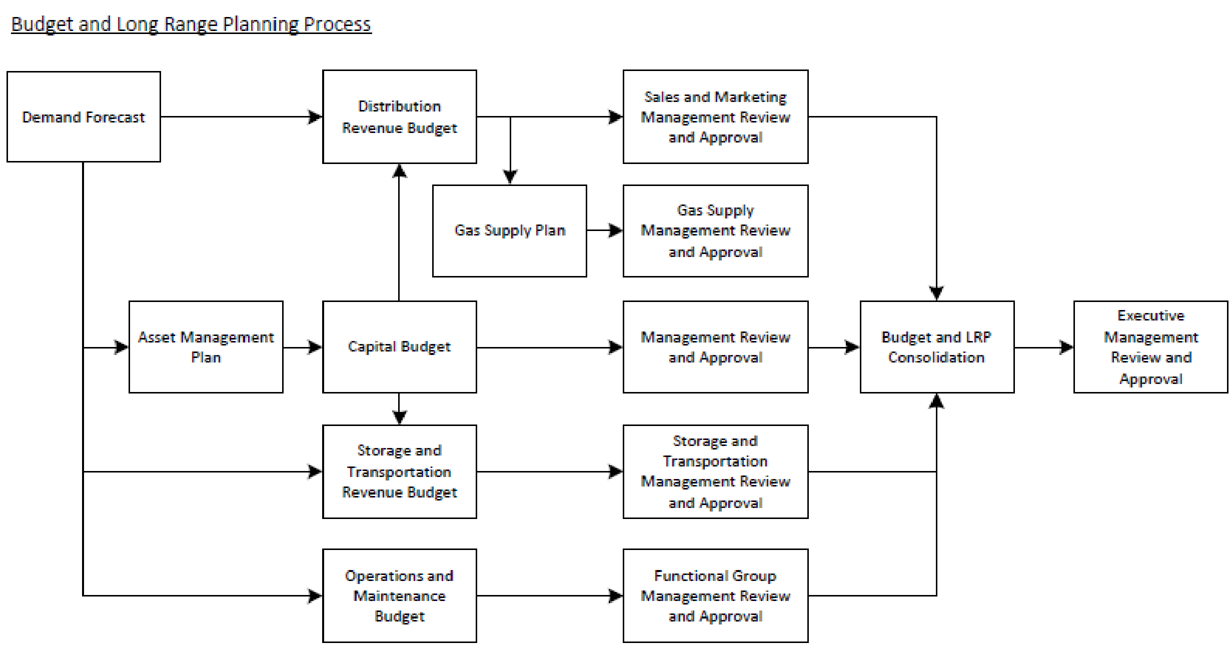
21. The demand forecast is the starting point for the budget and LRP process and includes a detailed customer and volume forecast. The demand forecast provides inputs into the four main components of the Company's financial budget and LRP process listed below, as well as the Gas Supply Plan process detailed within the Distribution Revenue Budget process.

22. Each component of the budget and LRP is individually described in the following sections:

i. Distribution Revenue
ii. Storage and Transportation Revenue
iii. Operations and Maintenance Costs
iv. Capital Investment

23. Figure 2 provides a process map for the budget and LRP process. The budget and LRP components include the impact of economic variables such as interest rates, foreign exchange rates, inflation levels, Gross Domestic Product ("GDP") forecasts, and provincial housing starts, where applicable.

Figure 2
Budget and Long Range Planning Process Map



3.2 DEMAND FORECAST

24. The starting point for the planning process is the customer, demand and volume forecast. This forecast underpins the development of both the revenue and cost components of the budget and LRP, and is used as an input into the Intregrated Resource Plan (IRP) and Asset Management Plan (AMP) process.

25. The annual demand forecast methodologies do not account for abrupt and unforeseen changes to economic conditions such as the COVID-19 effects. Enbridge Gas will address any changes to demand forecast methodologies as part of its 2024 rebasing application.

3.2.1 Distribution Revenue Budget

26. The distribution revenue budget is comprised of two distinct segments of customers: general service and contract. The forecast for each segment applies forecast rates for each year of the budget and LRP to the demand forecast in order to derive the revenue forecast for the utility.

Distribution Revenue - General Service Customers

27. The general service customer segment consists of residential and low-volume apartment, commercial and industrial customers. This segment is heat sensitive and also influenced by: economic conditions, housing starts, price, efficiency factors and energy conservation measures. The forecast is developed using legacy OEB-approved methodologies and criteria. Together these customers consume more natural gas from November through March than the spring and summer months.

28. The demand forecast for the general service segment is based on the current customer base plus forecasted additions less customer attritions. Gas usage is estimated for those current and forecasted customers and applied to the forecasted rates to create a revenue forecast.

Distribution Revenue - Contract Class Customers

29. The contract customer segment typically has higher consumption levels and is less heat-sensitive than the general service customer segment. Consumption for these customers is based primarily on process load, which is linked more closely to factors such as general economic health, industry growth, and customer expansion/contraction plans. Energy conservation measures and various macro-economic factors also play a role in consumption levels of this customer segment.

30. The demand forecast for this segment is based on the current contract parameters plus or minus changes in requirements for those customers, as well as the requirements of potential new customers. The forecast is based on a variety of methods including: direct engagement with current and potential customers, a thorough assessment of growth and demands by geographic area or market sectors (e.g. the power or chemical market), and by general trends reflective of

industry and general economic conditions. Where available, direct customer input is factored in the Company forecast.

Distribution Revenue - Incremental Capital Module (“ICM”)

31. Through the Capital Budget Process outlined below, eligible ICM projects benefiting in-franchise customers are identified. For those projects that meet the ICM elgibility criteria, the annual revenue requirements are calculated and subsequently added to the total Distribution Revenue Budget. The amounts added to the Budget form the basis of the annual Rates application.

Distribution Revenue Budget Review and Approval

32. The revenue forecasts for both the general service and contract class customers are consolidated and presented to the management team accountable for distribution revenue for review and approval. It is subsequently consolidated by Finance with the broader Company budget, and is reviewed and approved by the Company’s Executive Management Team.

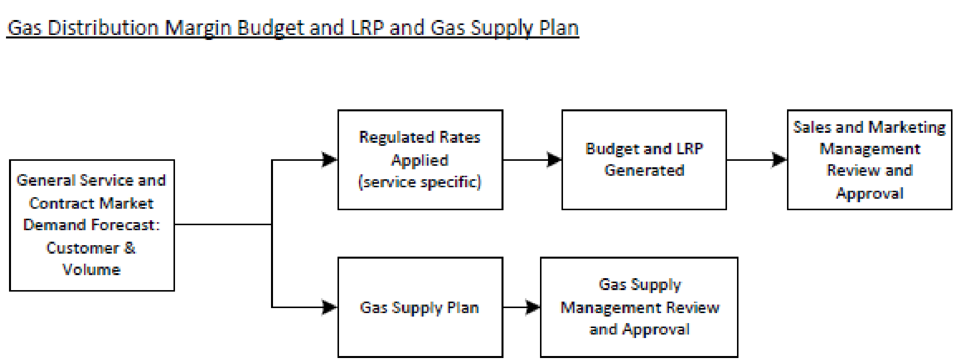
Distribution Demand Forecast as an Input to the Gas Supply Plan

33. The demand forecast for the Distribution segment is also an input for the Gas Supply Plan process. Econometric analysis is performed on historical consumption

demand data and customer specific consultation to provide the basis for the customer, per-customer consumption and volume forecast. The volume forecast is derived by combining the forecasted customer and forecasted usage to derive the total throughput volume forecast. The volume forecast is provided to the gas supply function for inclusion in the development of the Gas Supply Plan.

34. The objective of the Gas Supply Plan is to identify the most efficient combination of upstream transportation, supply purchases, and storage assets required to serve sales service and bundled direct purchase customers' annual, seasonal and design day natural gas delivery requirements under a set of gas supply planning principles. Balanced consideration of these principles ensures that customers have access to secure, reliable and diverse natural gas purchased at a prudently incurred cost.

Figure 3
Distribution Revenue Budget and Gas Supply Plan



3.2.2 Storage and Transportation Revenue Budget

35. The Storage and Transportation ("S&T") budget and LRP revenues are attributed to the sale of services using the Company's regulated storage and transportation assets.

Storage Revenue

36. The demand forecast, through the Gas Supply Planning process, is used to determine the amount of storage service required by in-franchise customers. These are customers who reside in Enbridge Gas' service area and require storage services to support their associated gas consumption needs. The Company's utility storage revenue is based on the sale of excess utility space, on a short term basis at market prices and a portion of net revenues are shared with shareholders. Available storage capacity is the excess of utility space that is not required for the regulated in-franchise markets. This is in accordance with the decision rendered by the OEB as part of the Natural Gas Electricity Interface Review ("NGEIR").

Transportation Revenue

37. The transportation revenue budget is based on the Company's sale of its transmission pipeline capacity. The Company sells both short-term and long-term transportation capacity, as well as exchanges.

38. The demand forecast, through the Gas Supply Planning process, is used to determine the amount of transportation service required to meet the needs of in-franchise customers. Additional capacity is available for sale to ex-franchise customers. Ex-franchise customers are not directly associated with consumption within Enbridge Gas' service area, but use the Company's services to transport gas to and from other interconnecting pipelines and markets or to supplement services offered to in-franchise customers. The transportation revenue forecast is based on current contracted demands as well as forecasted future demands. Existing contract parameters are reviewed to understand current contracted demands. Ongoing customer discussions inform the Company of changes to future demands and requirements of potential new transmission customers. This information is obtained through ongoing customer engagement with existing and potential customers, and through the transportation capacity open season process.

39. Capacity available for sale for transportation services is the transportation capacity in excess of what is used for purposes of serving the Company's in-franchise customers. If available capacity is not sufficient to meet the existing and forecasted future demand for transportation services, additional capacity may be created through the construction of new facilities or the consideration of integrated resource planning alternatives to meet the incremental demand. Capacity demands for both in-franchise customers and ex-franchise customers are factored into the AMP for asset classes providing these services.

40. Transportation services for rate classes M12/M12-X, M16, M17, and C1 long-term services are priced based on regulated rate schedules. C1 short-term transportation services and exchanges are based on negotiated rates. The transportation revenue forecast is the product of the forecasted rates for the respective transportation services, applied to the forecasted demands.

41. Through the Capital Budget Process outlined below, eligible ICM projects benefiting ex-franchise customers are identified. For those projects that meet the ICM elgibility criteria, the annual revenue requirements are calculated and subsequently added to the total Transportation Revenue Budget. The amounts added to the Budget form the basis of the annual Rates application.

S&T Revenue Budget Review and Approval

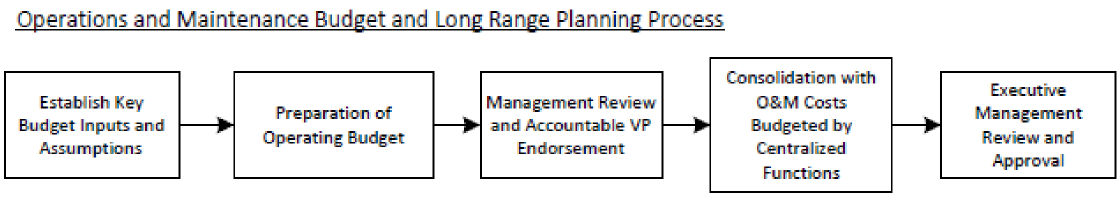
42. The revenue budget and forecast for utility storage and transportation services are consolidated and presented to the Management team accountable for utility S&T revenue for review and approval. It is subsequently consolidated by Finance within the broader Company budget, and is reviewed and approved by the Company's Executive Management Team.

3.3 Operating and Maintenance ("O&M") Expense Budget Process

43. The major steps in the O&M Budget process are illustrated in Figure 4 and described below:

   i. Establish Key Budget Inputs & Assumptions;
   ii. Preparation of Operating Budget;
   iii. Management Review and Accountable VP Endorsement;
   iv. Consolidation with O&M Costs Budgeted by Centralized Functions;
   v. Executive Management Review and Approval.

Figure 4
O&M Budget Process



Establish Key Budget Inputs and Assumptions

44. Assumptions are obtained by Finance from corporate and external sources for key input variables, including GDP growth, inflation, foreign exchange rate and expectations for compensation increases. These inputs and assumptions are reviewed by senior management and then used in the development of the Operating & Maintenance budget.

Preparation of Operating Budget

45. An operating budget is developed for each accountable area under a Vice President's reporting structure. The starting point for the operating budget is the previous year's budget/LRP which is then adjusted for compensation changes and inflation. The budget is then adjusted for any new program additions or deletions, or any program with material changes. Ongoing O&M costs associated with capital projects that have been placed into service are also incorporated. Changes in staffing requirements are considered, as is the need to employ consultants or

contract employees in order to complete the required workload in a safe, timely and cost-effective manner. Based on the resources required to carry out the work plan, relevant material, equipment, vehicle and employee expenses are incorporated into the budget. In addition, productivity and efficiency initiatives are identified to help manage cost increases.

Management Review and Accountable Vice President Endorsement

46. The budgets are reviewed at successively higher levels of management, with modifications made on an iterative basis as required. A final budget for each area is endorsed by the accountable Vice President responsible for each area.

Consolidation with O&M costs Budgeted by Centralized Functions

47. There are a number of Centralized Functions such as Finance, Human Resources, Information Technology, Supply Chain Management, Real Estate Services and Enterprise Safety & Operational Reliability that are resident at the Company and provide specific utility-based shared services. These functions are budgeted centrally at the corporate level, with input from the business units (including the utilities segment), on the business support required. These functions use a corporate cost allocation process to ensure that the Company is paying an appropriate amount for the services it receives from these Centralized Functions.

The endorsed O&M budgets from each of the accountable Company Vice Presidents (in the previous step) are then consolidated with the O&M budgets for the Centralized Functions to arrive at the total utility O&M budget for the Company.

Executive Management Review and Approval

48. The overall utility O&M budget is then consolidated by Finance with the broader Company budget and is reviewed and approved by the Company's Executive Management Team.

3.4 Capital Budget Process

49. The Company's capital budget process ensures that capital is allocated in a way that maximizes the value of life cycle-based assets while mitigating risk to the lowest practical level. This requires a combined effort from the Asset Management team, the business, and Finance to govern, prioritize, and execute the capital projects.

50. There are two primary objectives of the capital budget process:

    i. Ensure the proper governance structure and level of management oversight to enable the company to invest capital in the most efficient and effective way to meet the Company's obligations, ensure safety, and maximize the value of the investments; and

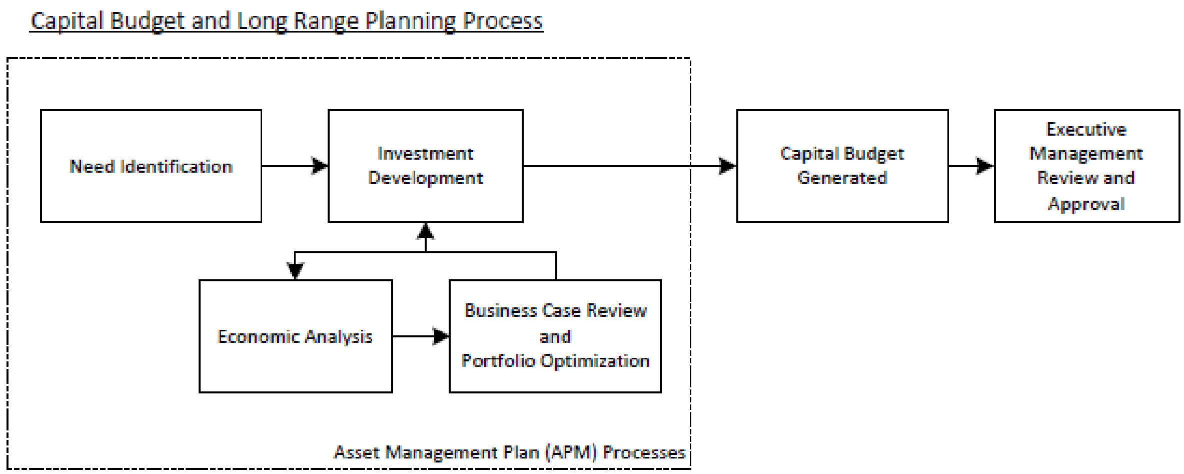
ii. Enable the business to plan and execute work in a timely fashion with minimal administrative burden, responding quickly to the demands of the customers that the Company serves.

51. The capital budgeting process is underpinned by the AMP. The AMP and how it is developed is detailed in Section 5. The AMP uses risk assessment methodologies to assess capital projects. These risk assessment methodologies, in combination with the defined asset decision making processes, form the basis for the selection and prioritization/optimization process for capital investments.

52. The major steps in the capital budgeting process are illustrated in Figure 5 and include:

i. Need Identification;
ii. Investment Development;
iii. Economic Analysis;
iv. Optimization of Portfolio and Review;
v. Consolidation and Executive Management Review and Approval.

Figure 5
Capital Budget and LRP Process



Need Identification

53. The need for a project is identified through the AMP process. The main drivers for capital expenditures are:

i. System integrity expenditures required to maintain or enhance the integrity of the company's plant, as well as to ensure compliance with codes and regulations governing the industry;

ii. System replacement expenditures required as a result of requests from municipalities and others under the terms of franchise or other occupancy agreements;

iii. Capital expenditures to replace plant, vehicles and equipment, computer hardware and software as a result of age, condition, or obsolescence;

iv. Capital expenditure requirements to meet expected growth as identified through the demand/revenue planning process and the gas supply planning process;

v. New programs that result in the need for capital expenditures.

54. Specific capital projects are identified to address the needs articulated above.

<u>Investment Development</u>

55. Project owners complete business cases for proposed projects that include: business needs or issues to be addressed, risks/opportunities, alternatives, and proposed solution. Customer engagement and preferences are used to help inform asset management planning decisions. This is described in greater detail in Section 4.1.1. Business cases also include other project specific parameters such as: scope of work, cash flows, key milestone dates, and risk results. Business cases must also ensure that the project conforms to company standard pricing, economic justification, and follow established engineering specifications, in relation to design, construction, safety, and method of installation. Depending on the size of the project, Enbridge Gas may need to file a Leave to Construct application with the Ontario Energy Board to determine if the project can be built.

Economic Analysis

56. Economic analysis of system expansion projects is completed using a Discounted Cash Flow ("DCF") method. EBO 188 and EBO 134 describe the parameters and methodology for the DCF.

i. EBO 188 describes the economic test that should be used to evaluate a proposed expansion of a gas distribution system.

ii. EBO 134 describes the economic test that should be used to evaluate a proposed expansion of a gas transmission system.

Optimization of Portfolio and Review

57. Upon completion of the economic analysis of a project, business cases are brought forward for review and approval, and optimization by the Asset Management group, in conjunction with Finance and Regulatory. Capitalized overheads are then allocated to capital projects based on the total spend of the Enbridge Gas portfolio.

Consolidation and Executive Management Review and Approval

58. The overall capital budget is reviewed within Finance to ensure that the budget is consistent with company targets and objectives, as well as to ensure compliance with capitalization policies and accounting standards. This ensures that only costs

which are capital in nature are included within the capital budget. The budget is reviewed from the perspective of both capital expenditure and in-service capital in order to assess the eligibility of projects as part of the Incremental Capital Module.

59. The consolidated capital budget is then presented to management for approval. It is subsequently consolidated by Finance with the broader Company budget, and is reviewed and approved by the Company's Executive Management Team.

3.5 Budget Approval

60. Once all of the components of the budget are reviewed by their respective accountable Vice President, the overall budget and LRP is consolidated to provide leadership with the Financial Plan for the Company. The consolidated budget and LRP is then reviewed and approved by the Company's Executive Management Team.

4.0 CAPITAL INVESTMENT PLAN

4.1 Project Selection Process

61. The Asset Management process begins with the identification of a risk or need. Operational risks and needs are identified on a systematic and ongoing basis. The asset management process is detailed in Section 4 of the AMP.

62. Enbridge Gas aims to prudently allocate resources to realize opportunities and manage asset risk, centralizing asset investment decision-making through a value and risk framework that balances risk, cost and performance across an asset's life cycle.

63. The application of asset management principles and an investment's net value are used to determine both its independent merit and its standing among other investments competing for resources in a constrained optimization process. The asset management tool Copperleaf C55 supports this process with value and risk modeling to determine the value investments contribute to the organization (including risk impacts), and investment portfolio optimization to understand optimal investments timing to maximize value to the organization. Risks and opportunities are evaluated consistently across asset classes.

64. Enbridge Gas has forecasted a 5-year capital investment plan (for both expansion and maintenance capital initiatives), where the portfolio optimization process was used to develop the capital forecast. Risks above a specific threshold are addressed within the constraints of the capital budget. A considerable portion of spend is driven by mandatory initiatives involving compliance related work and addressing risks that require a solution within a defined time. High risk projects

may trigger reprioritization of lower risk projects or may result in a request for ICM funding.

65. The asset management process is used for selecting core business investments. Despite their opportunities being evaluated using the same investment valuation framework, opportunities outside of core business activities that have different funding mechanisms and are driven and supported through public and governmental policies/regulations do not flow through this process (such as Community Expansion, renewable natural gas, etc.) and are not included in the AMP.

4.1.1 <u>Customer Needs and Overall System Planning Policy Objectives</u>

66. An important part of the asset planning process is the inclusion of customer needs (or interests) and preferences into the analysis of alternatives, pacing and optimization of capital plans. Enbridge Gas has taken a number of steps to gather information on customer interests and preferences and includes this information into the planning process.

67. In addition to its robust ongoing market research program, Enbridge Gas commissioned a third-party global market and research specialist, Ipsos Public Affairs, to conduct a customer engagement survey. This survey provides insight

into current customer satisfaction with Enbridge Gas as well as the needs and preferences regarding future initiatives and investment plans. This research is intended to complement Enbridge Gas's regular customer satisfaction surveys (which are used more frequently to monitor the perception and trust of customers as it relates to the interactions and dealings with the company) and more specifically focuses on:

- Overall customer satisfaction
- Satisfaction with safety, reliability, customer service, and value
- Willingness to pay for maintaining or improving service
- Pacing of spend

68. The Ipsos customer engagement survey collected feedback from both residential and business (contract and non-contract) customers. The results of this customer engagement inform Enbridge Gas's approach to its long-term plans.

69. Key themes formed by the responses include:

- Customers are satisfied with the service they are receiving from their natural gas service provider.
- Safety, reliability, and affordability are rated as being highly important customer outcomes by business and residential customers. When asked to rank the importance of various aspects of their natural gas service, providing stable and

predictable pricing is ranked within the top four categories among all customers, while minimizing the impact on the environment is ranked third among residential customers.

- When asked if Enbridge Gas should invest in improving or maintaining levels of natural gas safety, reliability and customer service, the highest proportion of residential customers would prefer that the organization focus on maintaining current levels.

70. These results demonstrate that customers value the safe, reliable, cost-effective, and environmentally responsible provision of natural gas. It also informs and reinforces Enbridge Gas's asset management decision-making framework. Enbridge Gas's values and guiding policy statements align with the preferences of customers in the following ways:

- The core asset management goals are employee and public safety, compliance, financial performance, value-based decision-making, environmental sustainability, and value to stakeholders.
- Enbridge Gas is committed to prudent value-based decision-making for all asset-related investments on a holistic evaluation of risk, cost, and performance.
- Enbridge Gas is committed to understanding and delivering value to its customers.

71. Section 2.4 of the AMP provides additional information on the customer engagement process and results.

<u>Integrated Resource Planning</u>

72. Integrated Resource Planning ("IRP") refers to a multi-faceted planning process that includes the identification, implementation, and evaluation of realistic natural gas supply-side and demand-side options (including the interplay of these options) to determine the solution for a peak system need that provides the best combination of cost and risk for our customers. Enbridge Gas is committed to IRP proceeding currently underway that will ultimately see the provision by the OEB of an IRP Framework. An IRP Framework will resolve outstanding policy issues to enable the fulsome planning and implementation where appropriate for alternatives to facilities that ensure customers' energy needs are met in a safe, reliable and affordable manner.

73. As part of its 2021 Dawn Parkway Expansion Project and IRP Proposal Application (EB-2019-0159) filed November 1, 2019, Enbridge Gas requested that the OEB make a determination that the policy direction set out in its IRP Proposal is reasonable and appropriate. The IRP Proposal submitted, sought to establish "an IRP framework to guide Enbridge Gas's assessment of IRPAs [IRP alternatives] relative to other facility and non-facility alternatives to serve the

forecasted needs of Enbridge Gas customers".[5] In its Procedural Order No. 1 for the 2021 Dawn Parkway Expansion Project proceeding the OEB determined that, "…the IRP Proposal, as it relates to future Enbridge projects, will be reviewed separately at a later date to be determined by the OEB."[6]

74. Through a combined letter and Notice of Hearing dated April 28, 2020, the OEB subsequently initiated a proceeding to review Enbridge Gas's IRP Proposal (EB-2020-0091). In its Decision on Issues List and Procedural Order No. 2 dated July 15, 2020, the OEB defined the scope for the IRP Proposal proceeding including a final Issues List and set out an initial procedural timeline. The OEB's latest procedural timeline, set out in Procedural Order No. 4 dated August 20, 2020, includes deadlines for Enbridge Gas, OEB Staff and approved intervenors to submit additional evidence and responding evidence from October 15, 2020 to December 11, 2020.

75. Consistent with the OEB's intentions stated in its Decision on Issues List and Procedural Order No. 2, to establish an IRP Framework for Enbridge Gas,[7] and considering Enbridge Gas's intention to file an illustrative IRP process plan that will include "a proposal for incorporating IRP into Enbridge Gas's system planning

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[5] EB-2019-0159, Exhibit A, Tab 13, p. 1.
[6] EB-2019-0159, OEB Procedural Order No. 1, pp. 1-2.
[7] EB-2020-0091, OEB Decision on Issues List and Procedural Order No. 2, p. 2.

processes (e.g. the Asset Management Plan);"[8] Enbridge Gas expects that the IRP Proposal proceeding will ultimately establish an IRP Framework that will enable consideration of IRPAs as part of the utility asset management planning process going forward.

4.1.2 Linkages and trade-offs between capital projects and ongoing O&M spending

76. In developing the asset management plan, Enbridge Gas considers ongoing O&M expenses and capital investments. In many cases it may be possible to continue to spend O&M dollars to extend an asset's useful life. However, as the condition of the asset degrades over time, O&M expenditures increase to the point that there is no economic benefit to continuing to operate the asset and renewal investment becomes the preferred option.

77. In general, Enbridge Gas's maintenance programs involve the expenditure of O&M dollars to complete inspections and repairs to maintain the required function of the assets. When it either becomes impossible or no longer cost-effective to continue to manage the assets in this fashion, capital renewal investment may be required to replace the asset or restore its function to its required level. Enbridge Gas's

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[8] EB-2020-0091, Enbridge Gas Letter, August 27, 2020, p. 1.

integrity management program includes O&M expenditures to perform inspections on the assets. The inspections have two possible outcomes:

i. no further action required as the health of the asset is deemed acceptable for continued service until the next inspection; or,

ii. some form of replacement or renewal is required that will require capital investment.

78. Risk is a factor in determining the appropriate time to make an investment to renew or replace an asset. Using the Risk Management processes outlined in the AMP, risks are identified and solutions are planned to achieve a risk reduction, balanced against the costs required to manage the risk.

4.2 ENGINEERING PLAN

79. Enbridge Gas's engineering plan is represented by the AMP. The purpose of Enbridge Gas's engineering plan is to provide the OEB and stakeholders with the supporting background and view of the company's forecast of capital expenditures over the forecast period. The plan is underpinned by an assessment of asset condition, system health and the risks associated with individual asset categories or classes.

80. Enbridge Gas gathers information through different means to inform its decisions. The work management and asset management systems gather key observations from inspection orders completed by frontline technical resources. Data is also derived from asset data systems and on-line data sources such as the Geographic Information System(GIS) , SCADA, and compressor data packages. The data from these various sources is then analyzed to identify trends and issues related to asset condition; for some assets, data can be combined with tacit knowledge to inform decision making. This may result in the need for revised maintenance attention through operating expense activities or capital renewals.

81. Section 4.1 details how the investments outlined in the engineering plan are identified and analyzed. The risk assessment process is described in Section 4 of the AMP and is underpinned by data. The information and analysis that is derived

from the data are used to help support business cases for the items that compose the five-year engineering plan.

82. Section 5 of the AMP details the engineering plan by asset class, and Section 6 further outlines the resultant capital expenditure requirements.

4.3 INVESTMENT CATEGORIES

83. Enbridge Gas investment categories have been mapped in Table 2 to the four general investment categories outlined in Chapter 5 of the Filing Requirements for Electricity Applications. The description of each investment category is as follows:

System access investments are additions and modifications (including asset relocation) to a distributor's system that a distributor is obligated to perform in order to provide a customer or group of customers with access to natural gas services via the distribution system.

System renewal investments involve replacing and/or refurbishing system assets to extend the original service life of the assets and thereby maintain the ability of Enbridge Gas's system to provide customers with natural gas services.

System service investments are modifications to a distributor's system to ensure the system continues to meet distributor operational objectives.

General plant investments are modifications, replacements or additions to Enbridge Gas's assets that are not part of its commodity-carrying system including land and buildings, tools and equipment, fleet vehicles and electronic devices and software used to support day to day business and operations activities.

Table 2
Investment Categories

USP Category	Asset Program
System Access	CC - Commercial/Bulk-Metered - Conversion CC - Commercial/Bulk-Metered - New CC - Industrial - Conversion CC - Industrial - New CC - Multi-Family/Apartment - Conversion CC - Multi-Family/Apartment - New CC - Residential - Conversion CC - Residential - New CC - Sales Station - Conversion CC - Sales Station - New CS - Growth DS - CNG TPS - Growth UTIL - Meters (growth) DP - Relocations GTH - Hydrogen Blending
System Renewal	CS - Improvements CS - Overhauls CS - Replacements DP - Corrosion DP - Main Replacement DP - Service Relay DS - Gate, Feeder & A Stations DS - Inside Regulator & ERR Program DS - Station Rebuilds & B and C Stations LNG - Replacements TPS - Improvements TPS - Replacements UTIL - Meters (mtc) UTIL - Regulator Refit UTIL - Remediation
System Service	CS - Integrity

USP Category	Asset Program
	DP - Damage Prevention DP - Integrity DP - MOP DS - Integrity Initiatives GTH - System Reinforcement LNG - Improvements LNG - Integrity TPS - Integrity UTIL - Integrity Survey UTIL - Monitoring Systems
General Plant	CS - Land/Structures - Improvements FLEET - Equipment & Materials FLEET - Tools FLEET - Vehicles LNG - Land/Structures - Improvements REWS - Furniture/Structures & Improvements REWS - Leasehold Improvements TIS Business Solutions TIS Infrastructure TPS - Land/Structures - Improvements

4.4 Capital Expenditure Summary

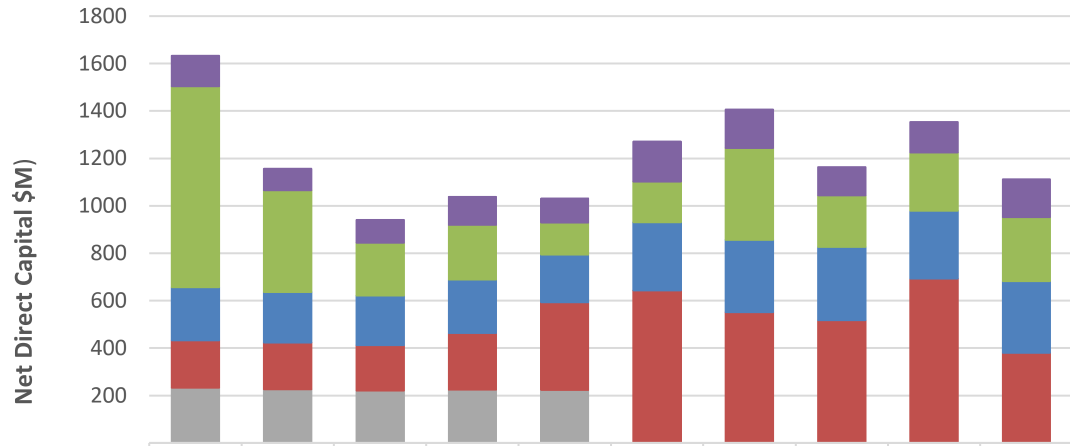
84. Enbridge Gas's total historical and total forecasted five year spend profile by investment category is illustrated in Figure 6. Enbridge Gas's projected spend totals $6.3 billion over the next five years; the projected annual spend ranges between $1.1 billion to $1.4 billion within the five year profile. System Renewal and System Access are Enbridge Gas's highest asset investment categories at $2.8 billion and $1.5 billion over the five years, respectively. This capital spend profile supports customer growth and reinforcement expenditures that will support the

addition of new customers, as well as expenditures associated with existing assets to maintain safe and reliable business operations.

85. The capital expenditure is the result of applying Enbridge Gas's asset management processes and principles to address:

- Asset needs as outlined in the AMP;
- Known compliance requirements;
- Identified risks within Enbridge Gas's intolerable risk region; and
- Identified risks requiring a solution within a defined time window.

Figure 6
Enbridge Gas's Capital Expenditure

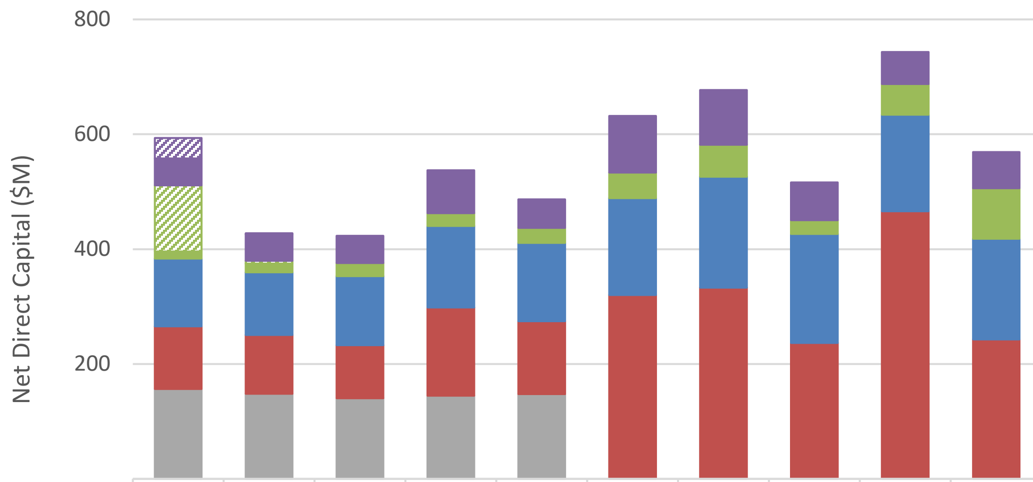


	2016A	2017A	2018A	2019A	2020B	2021F	2022F	2023F	2024F	2025F
General Plant	127	91	95	117	101	169	163	119	128	159
System Service	848	429	224	231	135	171	387	217	245	271
System Access	224	213	209	226	202	287	305	310	286	302
System Renewal	199	196	191	239	369	644	551	518	693	380
Overhead	234	227	221	225	224					
Grand Total	1632	1157	940	1038	1031	1270	1406	1163	1353	1112

Note: The total forecasted capital expenditures for 2021-2025 in Figure 6, Figure 7, and Figure 8 are comprised of each investment's direct costs and the associated overheads. Historical capital expenditure profiles for 2016-2019 and 2020 budget do not include associated overheads in the project costs. The associated overheads are identified as a separate category.

86. The EGD rate zone component of Enbridge Gas's capital expenditure profile is presented in Figure 7. The EGD rate zone projected spend remains at a consistent level and totals $3.1 billion over the five years. Historical spend for the System Service and General Plant investment categories are higher than projected due to large one-time initiatives approved through separate OEB approvals that have taken place, such as the GTA and WAMS projects.

Figure 7
EGD Rate Zone Capital Expenditure

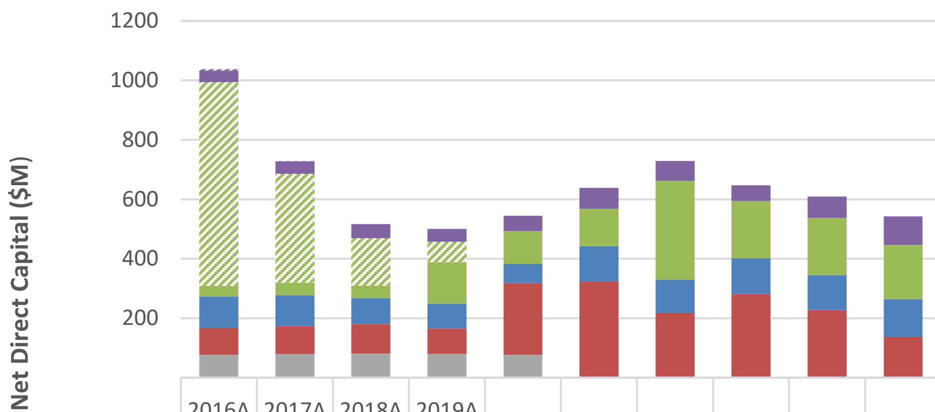


	2016A	2017A	2018A	2019A	2020B	2021F	2022F	2023F	2024F	2025F
General Plant (WAMS)	36	2								
General Plant	47	46	47	74	49	99	96	66	55	63
System Service (GTA)	115	5								
System Service	12	15	23	23	26	44	56	24	53	88
System Access	118	109	121	141	136	169	193	190	168	175
System Renewal	109	102	92	154	127	320	333	237	466	243
Overhead	156	148	140	145	148					
Grand Total	593	428	423	537	486	632	677	516	743	569

87. The Union rate zones component of Enbridge Gas's capital expenditure profile is presented in Figure 8. The Union rate zones projected spend totals $3.2 billion over the five years. The historical spend profile in system service category is primarily driven by growth on the Dawn-Parkway System, Panhandle, Burlington Oakville Project ("BOP"), Sudbury Replacement project as well as the Kingsville

Reinforcement project. In 2020 and 2021 there are two large renewal projects to replace vintage steel pipelines.

Figure 8
Union Rate Zones Capital Expenditure



	2016A	2017A	2018A	2019A	2020B	2021F	2022F	2023F	2024F	2025F
General Plant (Service Facilities Dawn)	6	1								
General Plant	39	41	48	43	52	70	67	54	72	96
System Service (BOP, Dawn, Panhandle, Sudbury, Kingsville)	685	366	159	70						
System Service	36	43	42	139	109	126	331	193	192	183
System Access	106	104	88	84	65	119	112	120	118	127
System Renewal	90	94	99	85	242	324	218	281	227	137
Overhead	77	79	81	80	76					
Grand Total	1038	729	517	500	544	638	729	648	610	543

88. For further breakdown and explanation of spend profiles in the EGD rate zone and Union rate zones, refer to Section 6 of the Asset Management Plan.

5.0 ASSET MANAGEMENT PLAN

89. The Enbridge Gas 2021-2025 AMP has been filed separately as part of this Enbridge Gas USP.

5.1 DESCRIPTION OF PLAN

90. Enbridge Gas has been implementing and continues to evolve its asset management tools for use by the business. Asset management tools provide the business with the ability to gather and make transparent decisions supported through the assessment of asset condition and risk. A new asset investment planning tool (Copperleaf C55) was implemented and an integrated asset management plan for Enbridge Gas was prepared.

Scope

91. The AMP covers all regulated assets inclusive of commodity-carrying assets directly related to the task of transporting natural gas from the source to the end-use customer, real estate, fleet and TIS assets that support business operation.

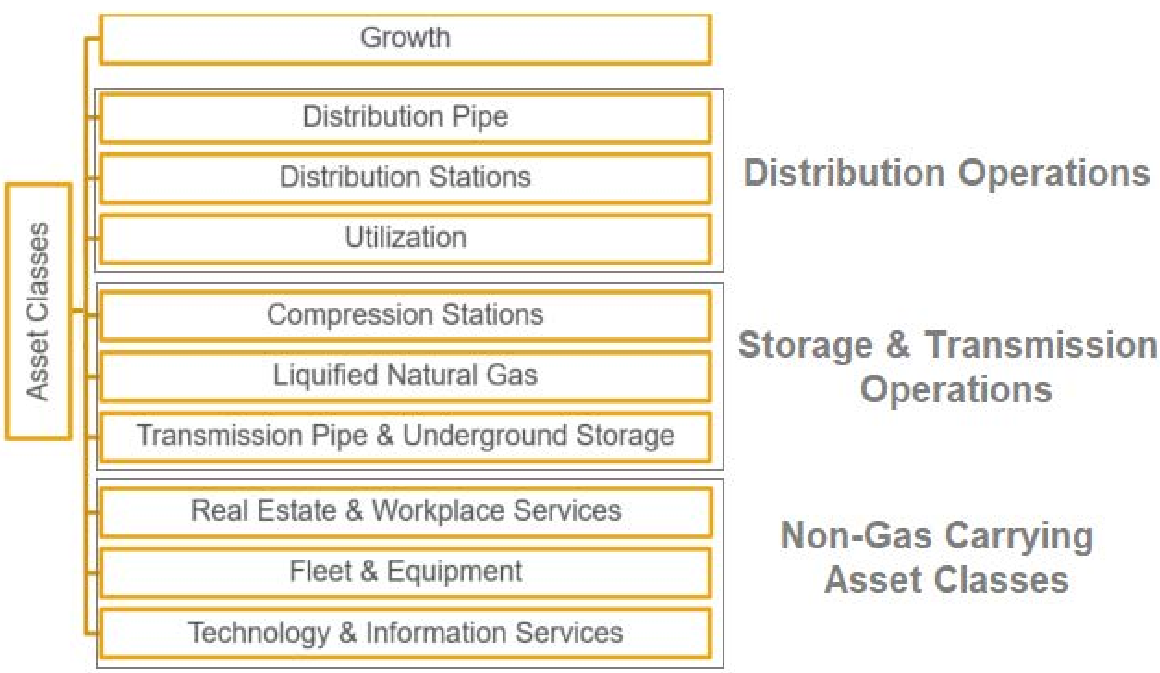
92. Through the AMP and asset management processes, investment opportunities and alternatives are evaluated to determine the expenditure of capital funding.

Five-year forecasts of capital investments for expansion and maintenance capital have been created for the EGD rate zone and Union rate zones.

Asset Classes

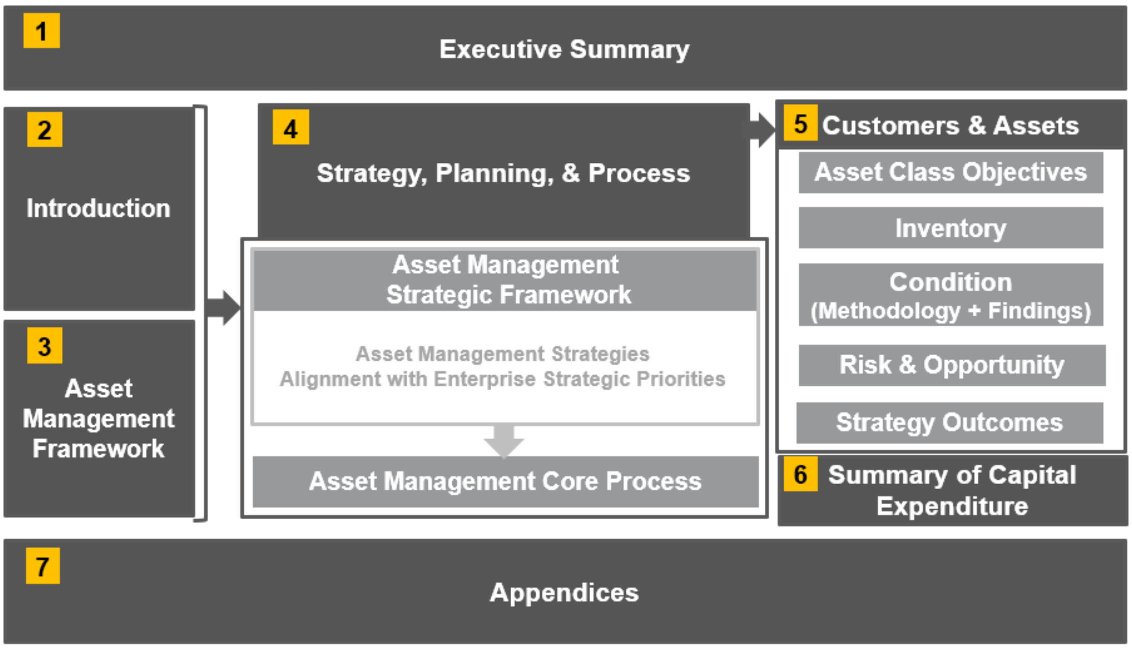
93. The following Asset classes are used to organize and define assets in the AMP.

Figure 9
Asset Classes in the AMP



Document Structure

Figure 10
AMP Document Structure



Risk Management

94. Enbridge Gas uses a Risk Management Process that is consistent with ISO 31000. A variety of Risk Assessment techniques are used that are appropriate to the decision that is to be made, the quality of information that is available, the immediacy of the need, and the nature of the risk. In many cases the risk assessment is progressive, starting with a relatively quick qualitative assessment which can evolve to a more quantitative assessment if there are multiple treatments to be considered.

95. Enbridge Gas aims to prudently allocate resources to realize opportunities and manage asset risk. The strategies to achieve this are:

- Establish a framework to identify, manage, and treat risk.
- Utilize processes for the identification, assessment, analysis, and treatment of risks and opportunities.
- Monitor asset performance and health to ensure a balance of risk, cost, and performance.

5.2 Alignment of Asset Management Plan to the Chapter 5 Requirements

96. The AMP was built using guidance from the OEB's filing requirements for natural gas distributors. Further guidance was obtained through the more detailed Chapter 5 of the filing requirements for electric distributors. Table 3 provides the alignment of sections of Enbridge Gas's AMP to the Chapter 5 requirements.

Table 3
Alignment of Enbridge Gas's Asset Management Plan Sections with the OEB's Filing Requirements

Chapter 5 - Filing Requirements (OEB)	Enbridge Gas AMP Section Reference
5.2.1 Distribution System Plan overview	Section 2: Introduction
5.2.2 Coordinated planning with third parties	Section 2.4: Stakeholder Commitment
5.2.3 Performance measurement for continuous improvement	Section 4.2.5: Performance Measurement Section 3.2: Enbridge Gas Integration & Continual Improvement Section 3: Plan-Do-Check-Act Principles
5.2.4 Realized efficiencies due to smart meters	N/A
5.3.1 Asset management process overview	Section 3: Asset Management Strategic Framework Section 4: Strategy, Planning, and Process
5.3.2 Overview of assets managed	Section 5: Customers & Assets (by asset class)
5.3.3 Asset lifecycle optimization policies and practices	Section 4.1.3 Life Cycle Delivery Section 5: Customers & Assets (by asset class)
5.3.4 System capability assessment for renewable energy generation	Section 3.3: Integrated Resource Planning
5.4.1 Capital expenditure planning process overview	Section 3: Asset Management Strategic Framework Section 4: Strategy, Planning, and Process Section 6: Summary of Capital Expenditure
5.4.2 Capital expenditure summary	Section 6: Summary of Capital Expenditure
5.4.3 Justifying capital expenditures	Section 3: Asset Management Strategic Framework Section 4: Strategy,Planning and Process Section 5: Customers & Assets (by asset class) Section 6: Summary of Capital Expenditure

5.3 BASE SPEND AND INCREMENTAL INVESTMENTS

97. Base spend represents the ongoing capital requirements of the utility to maintain safe and reliable operations and to economically attach new customers and pursue opportunities for innovation. This spend is driven by asset class strategies and program work that has sufficient risk and/or history to warrant continuation and is supported by existing rates (either through depreciation expense, annual Price Cap Index ("PCI") rate increases or increased revenues from customer growth).

98. Incremental investments are discrete projects requiring a total in-service capital investment of at least $10 million. They are driven by asset class strategies and are not supported by existing rates. Total incremental spend will include all capital costs associated with the identified project incurred up to the project's in-service year when ICM is requested.

99. Some examples include:

- Reinforcement projects needed to provide supply to a significant part of the franchise/customer area and cannot be constructed economically without a rate adjustment (e.g. Rideau, Owen Sound, Sarnia, Dawn-Parkway);
- Maintenance Projects of significant scope, that are outside the base upon which rates were based, and cannot be accommodated through a re-

prioritization of other capital spending (e.g. Dawn C Plant Replacement, London Lines Replacement, SCOR Meter Area upgrade);

- Significant Real Estate investments (e.g. Kennedy Road Expansion, SMOC/Coventry facility consolidation).

5.4 POTENTIAL ICM PROJECTS

100. Using the description of base spend versus incremental investment outlined in Section 5.3, the projects and the total in-service capital for which ICM treatment may be proposed are identified in Tables 4 for EGD rate zone and Table 5 for Union rate zones.

Table 4
Potential ICM Projects: EGD Rate Zone

Asset Class (Enbridge Gas)	USP Investment Category	Investment Name	In Service Date	(2021-2025) Forecast	In-Service Capital
Compression Stations	System Renewal	SCOR:Meter Area-Upgrade (Phase 1)	2021	$12.9	$49.3
Compression Stations	System Renewal	SCOR:Meter Area-Upgrade (Phase 2)	2022	$21.3	$23.0
Compression Stations	System Access	Dehydration Expansion	2023	$41.0	$49.1
Distribution Pipe	System Renewal	St. Laurent Phase 3 St. Laurent Plastic – Montreal to Rockcliffe St. Laurent Plastic – Coventry/Cummings/St. Laurent	2021	$12.4	$13.0

Asset Class (Enbridge Gas)	USP Investment Category	Investment Name	In Service Date	(2021-2025) Forecast	In-Service Capital
		St. Laurent Plastic – Lower Section			
Distribution Pipe	System Renewal	NPS 12 St. Laurent Aviation Pkwy[9]	2022	$29.5	$34.6
Distribution Pipe	System Renewal	NPS 12 St. Laurent Queen Mary/Prince Albert[9]	2022	$11.0	$12.9
Distribution Pipe	System Renewal	NPS 20 Lake Shore Replacement (Cherry to Bathurst) (2019+)	2022	$103.4	$127.7
Distribution Stations	System Renewal	Harmer District Station	2022	$13.1	$15.9
Distribution Growth	System Service	Thornton XHP reinforcement	2023	$10.9	$14.0
Real Estate & Workplace Services	General Plant	Kelfield Operations Centre Obsolescence.	2023	$10.8	$13.8
Real Estate & Workplace Services	General Plant	Station B New Building	2021	$15.5	$20.8
Real Estate & Workplace Services	General Plant	Kennedy Road Expansion	2023	$15.0	$20.9
Real Estate & Workplace Services	General Plant	SMOC/Coventry Facility Consolidation	2023	$30.8	$29.3

[9] *The St. Laurent portfolio of work consists of four phases of work, and each phase is comprised of separate projects. Phases 1 & 2 have been previously completed, with Phases 3 & 4 remaining in this forecast period. Phase 3 includes the following investments; Three PE main investments in 2021 including Lower Section, Coventry/Cummings/St Laurent, and Montreal to Rockcliffe. Phase 4 includes the following investments; Two steel main investments as included in this table in 2022. The investments comprising Phases 3 & 4 will be combined in a single Leave to Construct application that will be submitted in Fall 2020.*

Table 5
Potential ICM Projects: Union Rate Zones

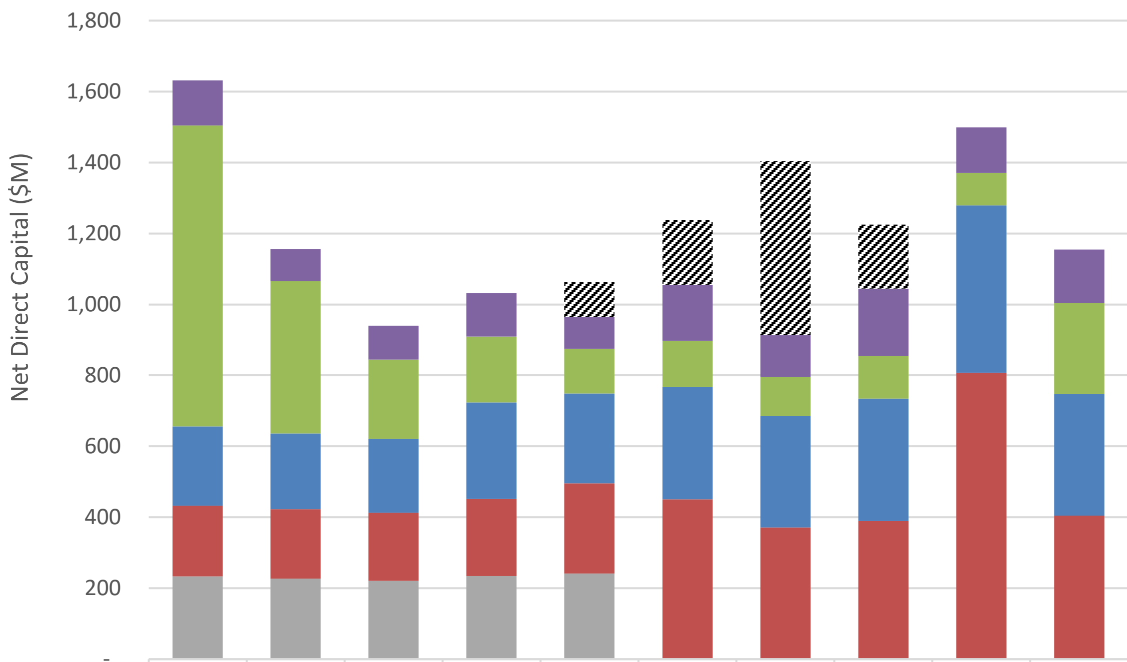
Asset Class (Enbridge Gas)	USP Investment Category	Investment Name	In Service Date	(2021-2025) Forecast	In-Service Capital
Distribution Pipe	System Renewal	LOND-London Lines Replacement	2021	$106.2	$124.0
Distribution Pipe	System Service	INTE: North Shore - Section A: Retrofit ECDA to ILI	2021	$12.0	$14.9
Distribution Growth	System Service	Customer Stratford Reinforcement	2022	$13.3	$16.3
Distribution Growth	System Service	Dunnville Line ReinforcementLoop 10" reinforcement from outlet of Caledonia Trans, ending at Stoneman Rd	2022	$9.1	$11.0
Distribution Growth	System Service	Ingersoll Transmission Station Rebuild	2022	$8.4	$10.3
Distribution Growth	System Service	NBAY: Install 12.5 km of NPS 6, Parry Sound	2023	$15.0	$19.3
Distribution Growth	System Service	Sudbury Transmission - 2 x 2100 HP Compressor upstream of coniston at Marten River takeoff	2022	$51.6	$65.9
Real Estate & Workplace Services	General Plant	New Site No. 4	2023	$28.8	$36.3
Transmission Pipe & Underground Storage	System Renewal	Panhandle Line Replacement	2023	$29.8	$34.0

Asset Class (Enbridge Gas)	USP Investment Category	Investment Name	In Service Date	(2021-2025) Forecast	In-Service Capital
Transmission Pipe & Underground Storage	System Service	2021 Dawn Parkway Expansion Project (Kirkwall-Hamilton NPS 48)	2022	$176.1	$213.9
Transmission Pipe & Underground Storage	System Service	INTE: Dawn - Cuthbert - ECDA to ILI Retrofit NPS 42, 34, 26	2022	$24.6	$29.9
Transmission Pipe & Underground Storage	System Service	SIL Reinf Proj - Phase 1 - DowVS to BWVS	2021	$19.2	
Transmission Pipe & Underground Storage	System Service	SIL Reinf Proj - Phase 1 - Novacor Stn	2021	$6.5	

101. Using the capital expenditure summary presented in Section 4, the total in-service capital required for identified ICM projects between the years 2021 and 2023 is illustrated by the hatched bars; all other base spend is represented as part of the appropriate investment category (see Figure 11, Figure 12 and Figure 13)[10]. Refer to the AMP for more details regarding the condition and strategies driving the need for these projects requiring significant investment.

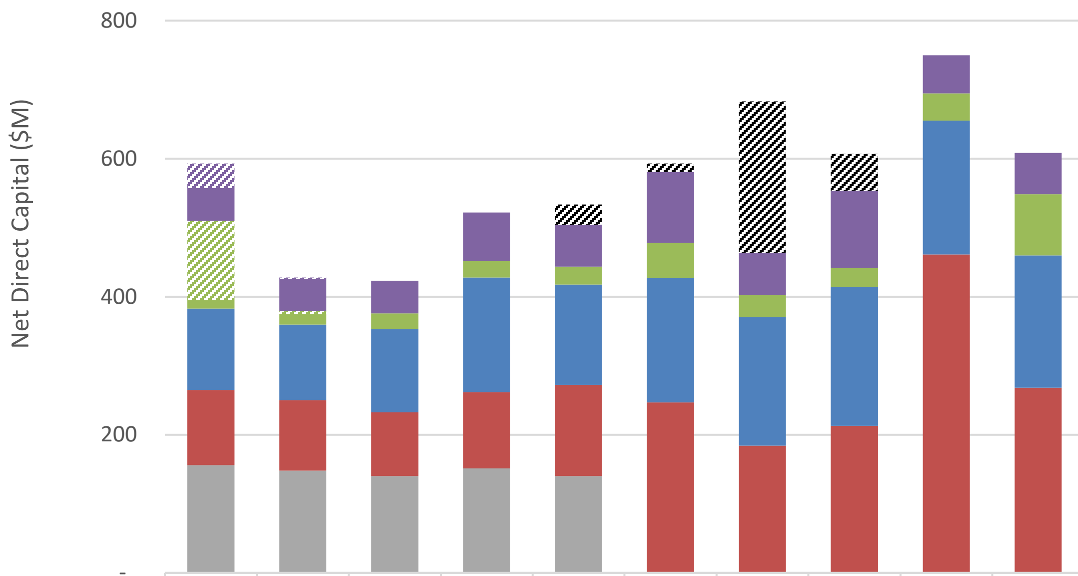
[10] ICM project spend in Figure 11, Figure 12 and Figure 13 represents the total in-service capital required for the project (including Overheads), compared to Figure 6, Figure 7 and Figure 8 in Section 4.4 where the capital expenditure profile represents the annual cash flow (which includes required preliminary and post spend for ICM projects). Details for Enbridge Gas's request for ICM funding can be found in Exhibit B, Tab 2, Schedule 1.

Figure 11
Enbridge Gas's Capital Expenditure Summary
(with proposed ICM project in-service spend identified from 2021-2025)



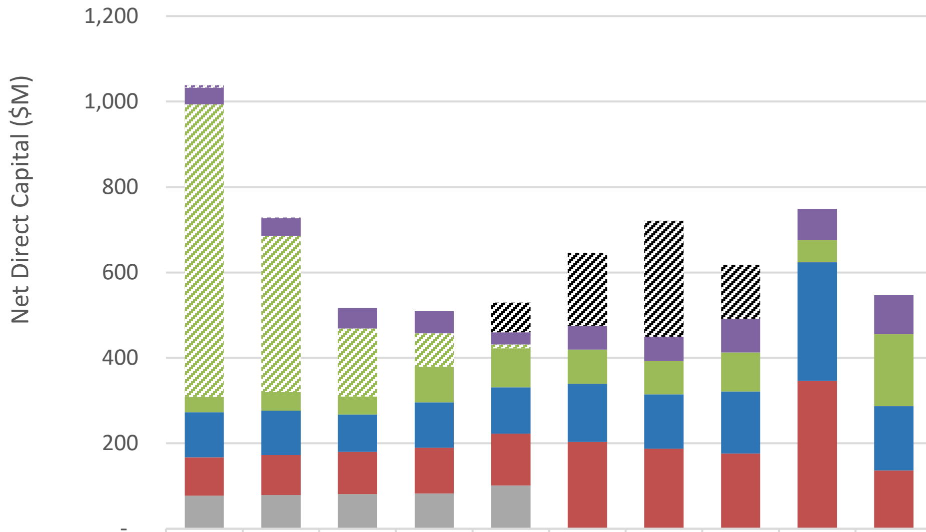
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
ICM Projects	-	-	-	-	99	183	491	180	-	-
General Plant	128	91	95	122	89	158	118	191	128	151
System Service	848	429	224	186	126	130	110	119	92	257
System Access	224	213	208	272	253	317	314	346	472	342
System Renewal	199	196	191	217	254	450	372	389	807	405
Overhead	234	227	221	235	242	-	-	-	-	-
Grand Total	1,632	1,157	940	1,032	1,064	1,239	1,404	1,225	1,499	1,155

Figure 12
EGD Rate Zone Capital Expenditure Summary
(with ICM projects in-service spend identified from 2019-2023)



	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
ICM Projects					29	13	220	54	-	-
General Plant (WAMS)	36	2								
General Plant	47	46	47	70	61	102	61	112	55	60
System Service (GTA)	115	5								
System Service	12	15	23	24	26	51	32	28	39	89
System Access	118	109	121	166	145	181	186	201	194	192
System Renewal	109	102	92	110	132	247	184	213	462	268
Overhead	156	148	140	152	140					
Grand Total	593	428	423	522	534	593	683	607	750	608

Figure 13
Union Rate Zones Capital Expenditure Summary
(with ICM projects in-service spend identified from 2019-2023)



	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
ICM Projects					70	170	272	126	-	-
General Plant (Service Facilities Dawn)	6	1								
General Plant	39	41	48	51.8	28	56	57	79	72	91
System Service (BOP, Dawn, Panhandle, Sudbury, Kingsville)	685	366	159	78.8	9					
System Service	36	43	42	83.3	91	80	78	91	53	168
System Access	106	104	88	106.2	108	137	127	145	278	151
System Renewal	90	94	99	106.4	121	203	187	176	346	136
Overhead	77	79	81	83.1	102					
Grand Total	1,038	729	517	510	530	645	721	617	749	546

6.0 BENCHMARKING

102. Another way Enbridge Gas have historically sought to continually improve is through industry engagement. Key subject matter experts involved in the design and operations of assets are engaged in industry related code committees and industry best practice committees to better understand compliance requirements,

to support the improvement of codes and standards that drive operational safety, and to learn and share best practices from industry peers. Examples include active membership of subcommittees for the Canadian Standards Association Z662 – Oil and Gas Pipeline Systems, Canadian Gas Association ("CGA") and American Gas Association ("AGA") surveys and workshops and participation in AGA peer reviews.

7.0 Other

7.1 Projects/programs Subject to Leave to Construct

103. In constructing hydrocarbon pipelines, Enbridge Gas follows the guidelines prescribed in the OEB Act. The guidelines require a leave of the OEB prior to constructing a hydrocarbon pipeline project subject to the following criteria:

- the proposed hydrocarbon pipeline is more than 20 km in length;
- is projected to cost more than the amount prescribed by the regulations (presently $2 million);
- any part of the proposed hydrocarbon line (i) uses pipe that has a nominal pipe size of 12 inches or more, and (ii) has an operating pressure of 2,000 kilopascals or more; and,
- Criteria prescribed by the regulations are met 2003, c.3, s. 63(1).

7.2 PROJECTS/PROGRAMS NOT SUBJECT TO LEAVE TO CONSTRUCT ("LTC")

104. Construction projects may not require approval from the OEB prior to construction in the following circumstances:

- the project does not meet the leave to construct criteria prescribed in the OEB Act;
- the project falls under federal jurisdiction that requires approval from the National Energy Board; or,
- the project involves relocation or reconstruction of an existing pipeline, unless the size of the line is changed or additional land is required.

7.3 CUSTOMER ADDITIONS AND PROFITABILITY INDEX VALUES

Customer Connections Feasibility

105. Enbridge Gas expands its distribution system in accordance with the OEB's guidelines for the expansion of natural gas service. These guidelines are articulated in the EBO 188 report. [11] The intent of EBO 188 is to facilitate rational expansion of natural gas service while protecting existing customers from undue cross-subsidization.

[11] EBO 188 Final Report of the Board, January 30, 1998.

106. For the general service market, Enbridge Gas uses a portfolio approach (Investment Portfolio and Rolling Project Portfolio) to manage distribution system expansion activities and ensures that required profitability standards are achieved at both the individual project and the portfolio level.

107. If the expansion is driven by large commercial/industrial customers (contract market), the feasibility analysis factors in the individual contribution of the customer to the project and assesses whether the customer would be asked to pay a Contribution in Aid of Construction ("CIAC"). This is explained in more detail below.

Investment Portfolio

108. This approach evaluates feasibility on all proposed new distribution customer attachments for a test year. The portfolio includes the costs and revenues associated with all new distribution customers forecasted to be attached in a particular year (including new customers attaching to existing main or infill services). The investment portfolio includes a safety margin to mitigate the forecast risk and achieve a PI threshold greater than 1.0 with the purpose of reducing undue cross subsidization.

Rolling Project Portfolio ("RPP")

109. This approach maintains a portfolio of system expansion projects over a rolling 12-month period. RPP is used as a management tool for estimating the future impact of capital expenditures associated with system expansion. RPP excludes customers attaching to existing mains (infill services). RPP is required to achieve a PI threshold greater than 1.0.

110. The figures below show the historical PI for the investment and RPP for both the EGD rate zone and Union rate zones.

Figure 14

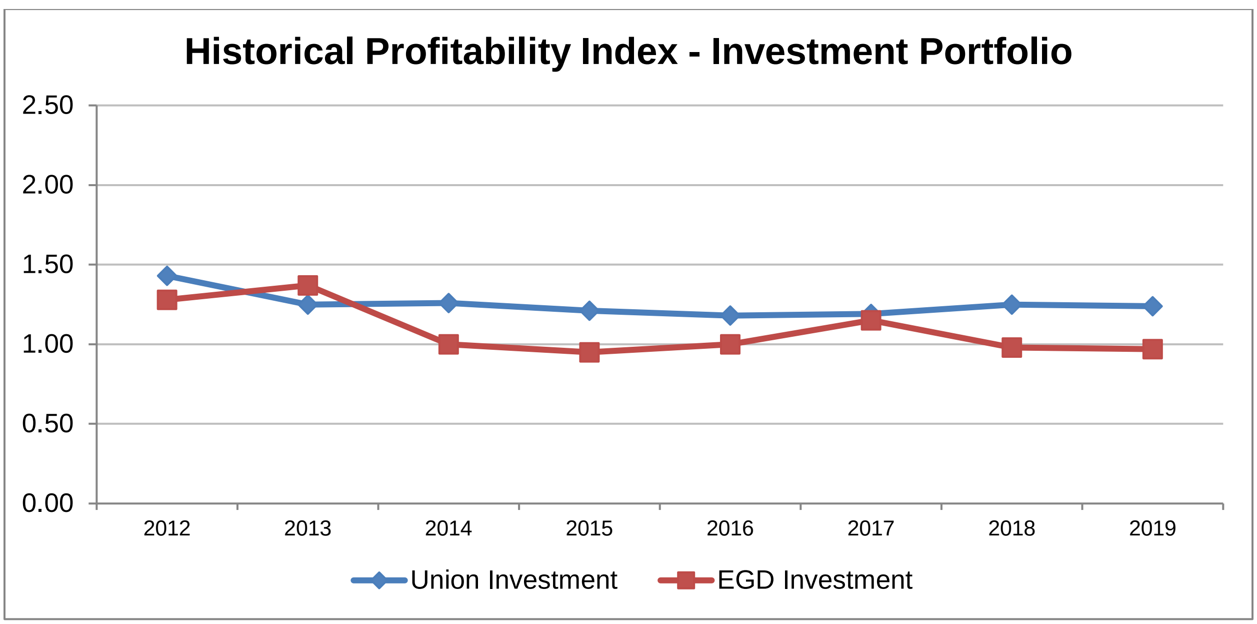
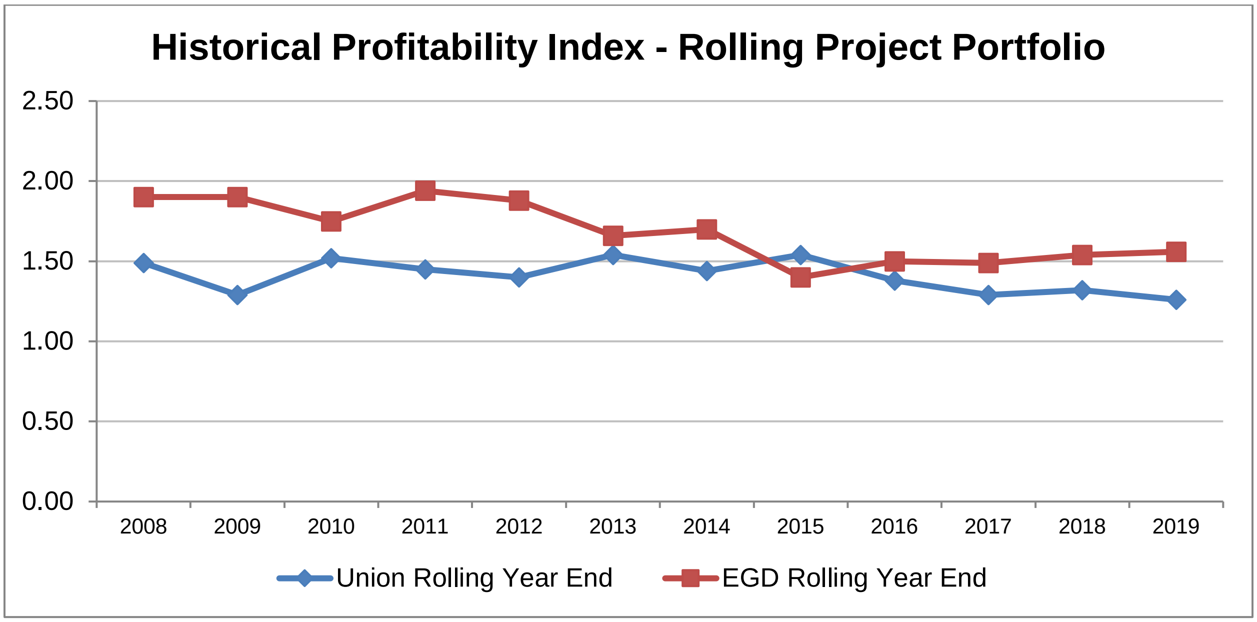


Figure 15


Historical Profitability Index - Rolling Project Portfolio
2.50
2.00
1.50
1.00
0.50
0.00
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
Union Rolling Year End
EGD Rolling Year End

Feasibility Process

111. When assessing the feasibility of a new project, Enbridge Gas prepares a forecast of project costs and revenues. Project costs include materials (e.g. pipe, couplings, meter sets), labour and equipment to install or construct the project. Costs related to reinstatement of the surface (such as road, sidewalk, landscaping) and the ongoing operation and maintenance of the project are also included in assessing project feasibility.

112. Enbridge Gas determines project feasibility using the estimated project costs and revenues. If the present value of project revenues is equal to or greater than the present value of project costs, the project is economically feasible and can proceed to be built. In such a case, over the life of the project, revenues will recover the entire cost of the project. Depending on the size and scope of a project, Enbridge Gas may be required to submit a LTC application for OEB approval. In approving an LTC application, the OEB may require that Enbridge Gas meet certain conditions.

113. When 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). The CIAC is the amount by which the project capital costs must be reduced by the customer to make the project feasible (i.e. to achieve the required PI threshold).

Feasibility Formula

$$\text{Profitability Index (PI)} = \frac{\sum PV(\text{Revenue} - O\&M + \text{CCA Tax Shield})}{\sum PV \text{ of Capital Cost}} \text{ or } PI = \frac{\text{Benefits}}{\text{Cost}}$$

114. The OEB recognizes that the amount charged as a CIAC is project-specific and varies depending on the costs and revenues for each project. The OEB has established feasibility guidelines and a formula for calculating the CIAC. Utilities can only charge a CIAC as prescribed by the OEB in EBO 188. If the customer chooses not to pay, the project is not built.

Benefits

115. The project revenues are based on the monthly customer charges and delivery charges of the forecasted customers and are netted against ongoing incremental operating and maintenance costs of the project.

Costs

116. Direct capital costs for a project include materials (e.g. pipe, couplings, meter sets, etc.), labour and equipment to install or construct the project, reinstatement of the surface (such as road, sidewalk, landscaping), and the ongoing operation and maintenance of the project.

117. Indirect costs for a project may include planning and design costs (Customer Connections, Construction, Network Planning and Land), gas distribution network capacity costs and administration costs attributable to customer growth such as inventory management.

Customer Growth Forecast

118. The customer growth forecast is a projection of how many new customers will be attached to the distribution system over the next 10 years. Information considered in developing this forecast includes development projects originating from direct contact with builders, developers and municipalities as well as economic factors and indicators from reliable third-party data sources. These factors include housing starts forecasts, GDP growth, employment and mortgage rates. Enbridge Gas has been consistently using this approach, which was approved by the OEB in previous rate applications.

119. There are important data considerations using this approach. For instance, a primary data source used in predicting growth is historical housing starts from Canadian Mortgage and Housing Corporation. For growth projections particularly

in the apartment sector, housing starts are much higher than the customer additions in the sector.

120. Further detail on the customer growth forecast is provided in the AMP.

7.4 PROJECTS UNDERTAKEN IN RELATION TO INITIATIVES FROM THE MINISTER OF ENERGY

121. The communities in Ontario that remain without natural gas service are distant from existing gas distribution infrastructure, have relatively low numbers of potential consumers, and may have terrain that precipitates high construction costs. These factors have limited the ability of Ontario natural gas distributors to serve these communities, as economic feasibility requirements cannot be met.

122. In 2016, the OEB issued a decision in its generic proceeding on new community expansion[12], which indicated that incumbent utilities could propose a System Expansion Surcharge ("SES") over and above existing rates to recover the shortfall in revenues to cover the cost of expansion and enhance the economic feasibility of community expansion projects.

[12] EB-2016-0094

123. The Ontario government enacted policy to assist in the development of new infrastructure to allow for natural gas service to reach rural communities and rectify energy inequities for these communities.

124. In September 2018, the Ontario government passed Bill 32 designed to support a ratepayer-funded model to help finance projects designed to provide new communities with access to natural gas.

125. To determine which communities will be qualified for gas service expansions, the Company assesses the economic feasibility for potential expansion (using the same process used for PI calculation). To move forward with community expansion projects, Enbridge Gas needs to be able to recover the costs associated with these projects in gas distribution rates. Many of these community expansion projects will still require the OEB's approval (where leave to construct approvals are required), and the application of the SES. Community expansion projects are categorized under the System Access category of projects. Refer to the AMP for further details. A number of other communities are currently being assessed for further community expansion opportunities through the application of the SES and the implementation of Bill 32 (Phase One of the Natural Gas Expansion Program).

126. Several community expansion projects were made possible through funding provided through Phase One of the Natural Gas Expansion Program. These projects included providing expanded access to natural gas to: the Chippewas of the Thames First Nation, the Northshore and Peninsula Roads areas of North Bay, the Saugeen First Nation, Cornwall Island, the Hiawatha First Nation, Scugog Island, and rural areas around Chatham-Kent. Enbridge Gas also expanded access to natural gas in Fenelon Falls, Prince Township, Kettle and Stony Point First Nation and Lambton Shores, Milverton, Rostock and Wartburg and the Delaware Nation of Moraviatown First Nation made possible with funding provided by the Ontario Government's Natural Gas Expansion Program.

127. Enbridge Gas is committed to building on Phase One successes by working with all levels of government to bring affordable, reliable natural gas to rural, northern and Indigenous communities across Ontario.

128. In December 2019, the Government of Ontario announced its intention to continue to expand access to natural gas with the Phase Two of the Natural Gas Support Program, allocating approximately $130 million to support new natural gas expansion projects.

129. Enbridge Gas has submitted a number of community expansion projects to the Ontario Energy Board for review and consideration for Phase Two funding. The Ontario Energy Board will provide recommendations to the Ministry of Energy, Northern Development and Mines to assist in determining which future expansion projects will receive funding.

130. A number of other communities are currently being assessed for further community expansion opportunities through the application of the SES and the implementation of Bill 32.

EGI Asset Management Plan 2021-2025

October 5, 2020

Report

Company: Enbridge Gas Inc.

Owned by: Asset Management Department

Controlled Location: Asset Management Teamsite

ENBRIDGE

EGI Asset Management Plan 2021-2025

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1. Executive Summary

1.1 Document Purpose

On January 1, 2019, Enbridge Gas Distribution (EGD) and Union Gas Limited (UGL) amalgamated to form Enbridge Gas Inc. (EGI). EGI is comprised primarily of natural gas utility assets and operations that serve over 12 million consumers with 3.7 million residential, commercial and industrial connections in Ontario, serving over 355 municipalities and 21 First Nation communities. EGI's 280 billion cubic feet (approximately five billion cubic metres) of storage assets are tied to large and growing demand centres in Canada and the U.S. and provide a critical link to low-cost natural gas supplies. The management of these assets is important for the safe and reliable delivery of natural gas to customers. Asset management at EGI ensures that value is realized through its assets while managing risk and opportunity.

The purpose of this Asset Management Plan (AMP) is to outline:

- Policy and strategies for establishing effective asset management for all utility assets within EGI's regulated operations
- Process and governance for asset management
- Asset class objectives and life cycle management strategies
- Asset inventory, condition methodology, condition findings, risks, opportunities and renewal strategies
- Optimized five-year capital plan required to manage assets from 2021-2025

This Asset Management Plan aligns with the *ISO5500X* industry standard, the Institute of Asset Management (IAM) and the Global Forum on Maintenance and Asset Management (GFMAM). This document is intended to meet the OEB's expectations as set out in the *Handbook for Utility Rate Applications* and the *Filing Requirements for Natural Gas Rate Applications*.

1.2 Structure of the Asset Management Plan

Figure 1.2-1 is an illustration of EGI's Asset Management Plan structure.

Figure 1.2-1: EGI's Asset Management Plan Structure

Introduction (Section 2) and **Asset Management Strategic Framework (Section 3):** This plan starts with an introduction to EGI. It also highlights EGI's stakeholder commitment, the asset management framework and policy, updates and improvements from previous Asset Management Plans and the structure of the document.

Strategy, Planning and Process (Section 4): This section details the alignment of asset management at EGI with the enterprise strategic priorities and includes EGI's asset management strategies and the asset management core process.

Customers and Assets (Section 5): This section details the following for each asset class:

- Asset class objectives
- EGI's customers and the customer growth projections
- Asset inventory
- Asset condition
- Risks and opportunities

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- Strategy outcomes
- Capital investments to meet life cycle strategies

Summary of Capital Expenditure (Section 6): This section summarizes the five-year capital investment plan for EGI by rate zone, outlines the optimization process and highlights key assumptions used for **Sections 5** and **6**. Note that projects where solution scopes are still under development are not currently included in EGI's five-year portfolio of spend.

Appendices (Section 7): The appendices present supporting information for the Asset Management Plan.

1.3 Company Purpose, Vision, Values and Strategic Priorities

Enbridge exists to fuel people's quality of life with a long-term vision to be the leading energy delivery company in North America. Enbridge Gas Inc. (EGI) is committed to the safe, reliable, cost-effective and environmentally responsible provision of natural gas to its customers. Enbridge continues to build on its foundation of operating excellence by adhering to a strong set of core values–Safety, Integrity and Respect–in support of its communities, the environment and its people.

In **Figure 1.3-1**, it can be seen that natural gas delivers a significant portion of Ontario's energy needs on both a peak and average basis. EGI is well-positioned to provide affordable energy and contribute positively to the low-carbon economy through the safe and reliable delivery of natural gas and a commitment to low-carbon alternatives such as hydrogen blending and renewable natural gas. Natural gas continues to be cost-effective when compared to electricity.

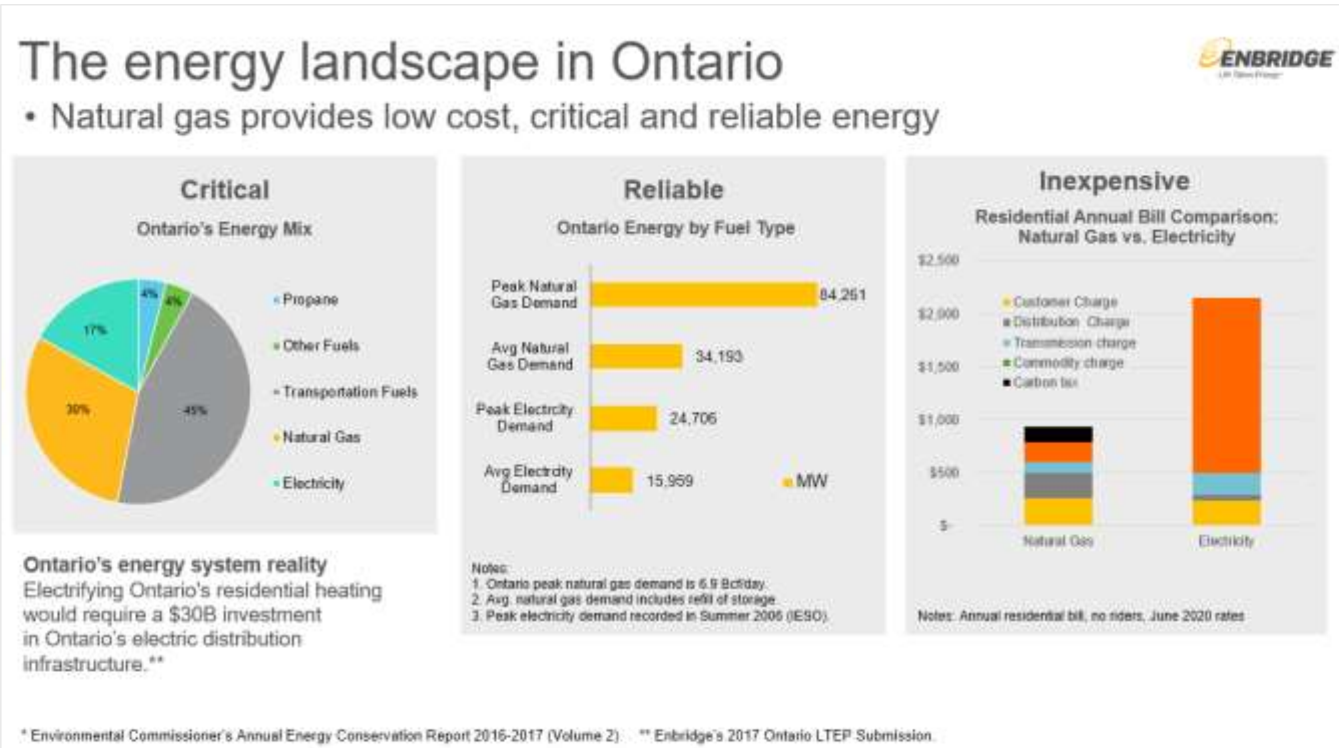

Figure 1.3-1: The Energy Landscape in Ontario

Asset management supports Enbridge's purpose, vision and values by improving the company's ability to operate safely and reliably, ultimately maintaining the satisfaction of our customers and other stakeholders. Optimal value will be delivered to customers and stakeholders through a sustainable investment plan that balances risk, cost and performance.

Core asset management goals are employee and public safety, compliance, financial performance, value-based decision-making, environmental sustainability and value to stakeholders. EGI employees must consider these goals when evaluating risks, costs and performance related to asset investment decisions. These goals should also be considered during the installation, operation, maintenance and disposal of assets.

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Asset management provides the necessary structure to make informed asset decisions and execute the resultant actions. In this regard, it is imperative that the framework of asset management at Enbridge is aligned with enterprise strategic priorities (**Figure 1.3-2**).

Figure 1.3-2: Enbridge Enterprise Strategic Priorities

1.4 Customer Service Area and Assets

EGI serves over 3.7 million residential, commercial and industrial customers in Ontario, delivering heating to more than 75% of Ontario's homes. Between 2020 and 2030, EGI's customer growth is forecasted to be more than 40,000 customers annually. EGI's franchise area is divided into seven operating regions as shown in **Figure 1.4-1**:

- Northern Region covers the legacy UGL Eastern, Northwest and Northeast districts.
- Eastern Region covers Ottawa and the surrounding region.
- Southwest Region covers the Windsor/Chatham and the Sarnia/London areas.
- Southeast Region covers the Waterloo/Brantford and the Halton/Hamilton areas.
- GTA West and Niagara Region covers the western Greater Toronto Area (GTA) and Niagara.
- GTA East Region covers the eastern Greater Toronto Area.
- Toronto Region covers the city of Toronto.

EGI has storage and transmission assets that serve to receive, store and transport natural gas for markets in Ontario, Quebec, the Maritimes and major U.S. natural gas consuming areas. EGI's Dawn Hub in southwestern Ontario is connected to most of North America's major natural gas basins, including abundant and affordable gas supplies in the Western Canadian Sedimentary Basin and the Utica and Marcellus producing regions. It is similarly connected to the major demand markets. Like spokes of a wheel, more than half a dozen major pipelines connect at Dawn.

EGI transports gas from the Dawn Hub to the GTA through its West, Central and East transmission operations areas.

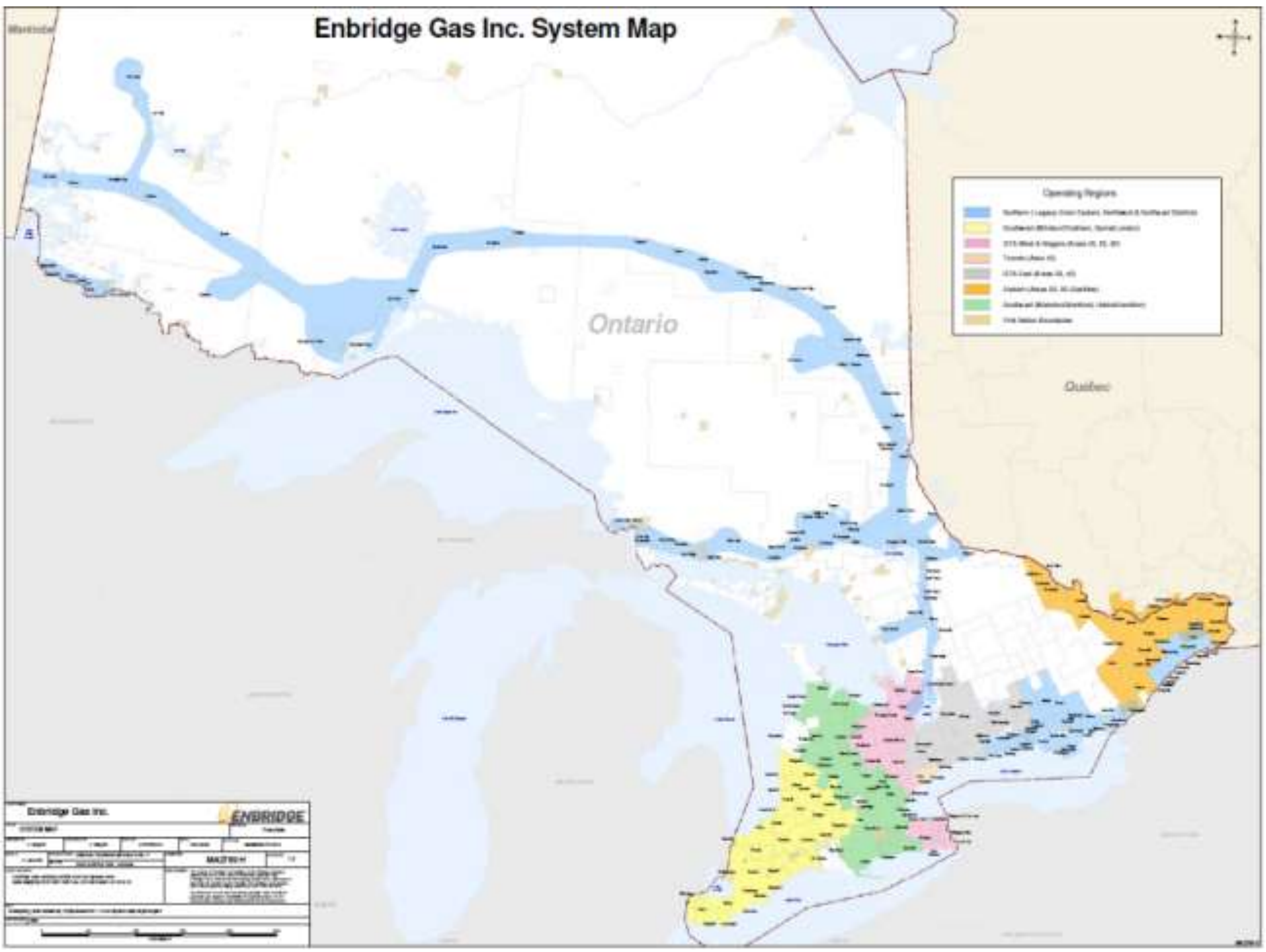

Figure 1.4-1: EGI Operating Regions

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Storage and transmission assets include transmission pipe of up to nominal pipe size (NPS) 48 used to transport natural gas across Ontario, compressor plants to move natural gas to and from storage reservoirs and along the transmission pipelines and a liquefied natural gas plant used to support peak shaving in one area of the company.

EGI's distribution assets include smaller diameter pipe, stations, meters and regulators at homes in the franchise areas. EGI's supporting assets include buildings, fleet vehicles and technology and information services (TIS) assets across Ontario that support EGI's critical business needs and activities.

EGI has a network of natural gas assets that serve to receive, store, transport and distribute natural gas. **Figure 1.4-2** shows how these assets and those that support them are interconnected to provide safe and reliable natural gas to EGI's customers.

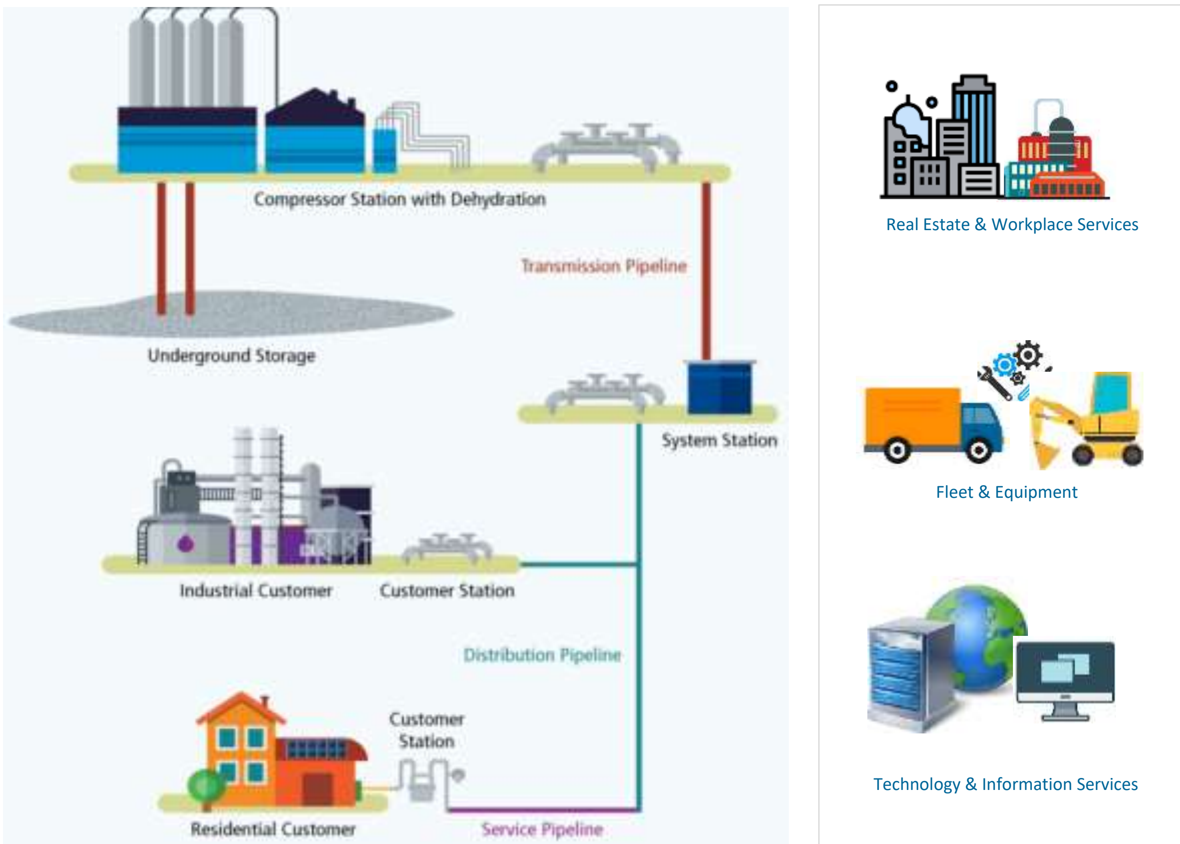

Figure 1.4-2: Components of a Natural Gas System and Supporting Assets

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1.5 Advancing Asset Management

On October 25, 2019, EGI filed an Asset Management Plan (AMP) Addendum to the 2019-2028 AMPs previously filed by EGD and UGL, to provide an update to budget year 2020 for each of the two existing plans. This 2021-2025 AMP document reflects the integrated utility's Asset Management Plan for the next five years, with assets for the rate zones (the EGD and Union North and South rate zones) being maintained separately for capital planning purposes through to the end of 2025[1].

EGI continues to evolve its asset management practices to produce a comprehensive Asset Management Plan. As a result, the following changes were implemented:

- **Alignment with Enbridge Inc.'s 2020 Enterprise Strategic Priorities**

  Enbridge Inc. published a revised Strategic Plan in 2020. The alignment of EGI's Asset Management Policy, Asset Management Strategies and dimensions of risk have been reviewed to confirm alignment and are found in **Section 4**.

- **Implementation of a new asset investment planning tool**

  Copperleaf C55 is an asset investment planning tool that centralizes asset investment decision-making through a value and risk framework that balances risk, cost and performance across an asset's life cycle. C55 was implemented at EGI in January 2020, as part of Enbridge Inc.'s Enterprise Asset Management program. Use of a single tool will provide consistency across the integrated company and visibility to investments that are part of the plan as well as those that are required to address emergent concerns, changes to municipal or customer needs and changes to cost estimates. C55 will help EGI evaluate options, efficiently manage its dynamic portfolio of asset investments, provide the governance and oversight to achieve the best return for its investments and satisfy regulatory commitments.

- **Organizational structure changes to align roles and responsibilities within the integrated utility**

  The amalgamation of the legacy utilities included alignment of roles across both organizations. A new asset management reporting structure was set up with asset manager roles aligned to new processes, asset class hierarchies, governance roles and functional department support. A matrix approach to asset management enables the coordinated activity of defining an optimized and approved portfolio of work. This streamlines inputs from a diverse group of business stakeholders, while growing asset management practices across EGI. Specific roles and accountabilities in the matrix approach include:

  - **Asset Managers**: accountable to manage asset performance, support maintenance and operations and lead an asset knowledge community within their respective asset classes in identifying risks and opportunities.
  - **Asset Management Governance**: accountable for overall the governance of systems and methodology, risk management framework and analysis, portfolio optimization and the Asset Management Plan.
  - **Knowledge communities consisting of Subject Matter Advisors (SMAs)**: accountable for supporting asset managers on hazard or opportunity identification, investment assessments, planning and project execution.

- **Consolidation of UGL asset data**

  The systems of record for asset data in the Union rate zones include Banner for meter data, Service Suite for work and condition data, RiskMaster for damages, SAP-PM for station work and asset data, GIS for pipe data and CORR for corrosion data. An initiative was completed in Q3 2019 to document and create a copy of this information in a centralized data repository through a series of extract, transform and load (ETL) interfaces. The documentation and consolidation of UGL data enabled EGI to more efficiently analyze inventories for the combined utility and support the development of the consolidated Asset Management Plan.

- **Evolution of asset condition and strategies**

  Section 5, which addresses asset inventory, condition, risk/opportunity and strategy outcomes, has been updated to reflect the current understanding of assets. Specific project and program information is provided in **Section 6** to support each asset class's strategic plans. Key changes are:

  - Review, comparison and integration where feasible of asset strategies, asset classes, asset condition, inventories, programs and processes between the two legacy companies
  - Identification of outstanding items that remain in legacy programs until they can be integrated

Given the impact of COVID-19 to resourcing and potential uncertainty surrounding longer term forecasting, development of the Asset Management Plan has been affected in 2020. Adjustments were made in these new working arrangements to 2020

[1] *The deferred rebasing period is from 2019-2023. Asset Management will reflect the new regulatory framework once it becomes available.*

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planned activities to adjust the scope of the 2021 Asset Management Plan from 10 years to five years, thus the plan has been prepared for the years 2021 to 2025.

In addition to EGI's newly implemented C55 asset investment planning tool, prioritization of projects was completed using legacy asset management plans, existing asset strategies and input from SMAs and business units to prioritize capital requirements in conjunction with the optimization process.

As a result of being in the early stages of implementing a new tool/application C55 (and responding to COVID 19 resourcing and other challenges), the current AMP was developed through a combination of the following to come to a proposed budget:

- C55 optimization
- Asset manager input
- Stakeholder input

1.6 Asset Management

The Institute of Asset Management (IAM) Conceptual Asset Management Model (**Figure 1.6-1**) has been used to build and implement an asset management framework at EGI to balance risk, cost and performance through the entire asset life cycle. By adopting the IAM model, EGI ensures alignment with the *ISO 5500X* standard and demonstrates connections between the subjects of asset management and the elements of the EGI Integrated Management System. This model also provides a visual representation of how the asset management discipline connects the various elements and functions across the organization. It further defines asset management planning as the detailed activities, resources and responsibilities for the achievement of asset management goals. This guidance has been used to develop the content and strategy of this Asset Management Plan.

Figure 1.6-1: IAM Conceptual Asset Management Model

Within this framework, the asset management process includes the following activities:

- Determining EGI's strategic framework
- Identifying risks, opportunities and their resultant investment options
- Outlining how optimized decisions are made for the strategic investment plan and annual portfolio plan (i.e., the Asset Management Plan)
- Explaining how asset management performance is measured
- Outlining the tools, data and analytics that support these activities

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1.7 Asset Classes

The Asset Management Plan considers all OEB-regulated assets, which have been grouped by asset class (**Figure 1.7-1**):

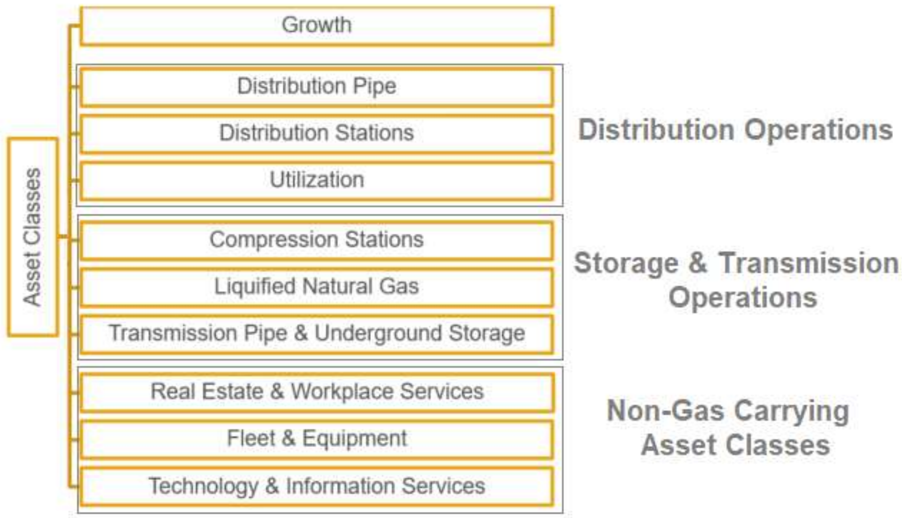

Figure 1.7-1: EGI Asset Classes

Investment decisions are categorized and managed on an asset class basis, where each asset class has a unique set of objectives and life cycle management policies that guide decision-making. With an understanding of the asset inventory and the evaluation of condition and risk, resultant strategies are outlined.

1.8 Condition and Strategy Overview

An overview of each asset class's condition, risks and opportunities and maintenance & replacement/renewal strategies are discussed in the following subsections:

1.8.1 Growth Condition and Strategy Overview

Asset Subclass	Condition	Risk / Opportunity	Strategy
Customer Connections	Between 2009 and 2019, EGI's customer growth was on average 52,800 customers per year (32,700 and 20,100 for the EGD and Union rate zones respectively). Between 2020 and 2030, EGI's customer growth is forecasted to be more than 40,000 customers annually.	EGI is expected to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers (*EBO 188*), where feasibility is quantified by determining the value of a project's revenues against its costs (the Profitability Index or PI).	The strategy for the Customer Connections asset subclass is to continue to ensure required infrastructure is installed to enable the addition of all forecasted customers that are feasible under *EBO 188* guidelines, while following harmonized forecasting practices. EGI continues to monitor and update the customer additions forecast through the annual long range planning process. Economic feasibility for growth is based on *EBO 188* guidelines applied to the investment portfolio and rolling project portfolio. The service length threshold without any cost to a residential infill (conversion) customer is 20 and 30 metres for the EGD and Union rate zones respectively. For longer services greater than these limits, customers pay a contribution at a rate of $32/metre in the EGD rate zone and $45/metre in the Union rate zones.
Distribution System Reinforcement	Load gathering and simulation, annual forecasting and long range system planning are completed. Areas requiring reinforcement have been identified.	Ensure security of system supply to existing customers and support forecasted customer growth using *EBO 188* guidelines.	The strategy for the Distribution System Reinforcement asset subclass is to implement specific reinforcement solutions in a timely manner to enable forecasted customer growth while maintaining safe and reliable operations. Long-term reinforcement plans are being completed per existing processes and alignment continues as part of integration activities. Integrated Resource Planning (IRP) will be considered based on the outcome of the IRP proceeding currently before the OEB.
Transmission System Reinforcement	EGI's major transmission systems, which include the Dawn Parkway System, the Panhandle System and the Sarnia Industrial Line (SIL) System move natural gas from receipt points to delivery locations along the pipeline to meet the volumetric demands and pressure requirements of EGI's in-franchise and ex-franchise customers. The pipeline system forms the foundation for future development as customers' needs grow and represents the supply into many of EGI distribution networks. The reinforcement process includes identifying the purpose, need and timing of reinforcements, design day demand development, incorporation of corporate growth forecasts, model simulation and short- and long-range planning.	Ensure safe and reliable transmission system operations and support interconnect and end use growth using *EBO 134* guidelines.	The strategy for the Transmission System Reinforcement asset subclass is to implement specific reinforcement solutions in a timely manner to enable forecasted customer growth and to support distribution growth and reinforcement. In some cases, there is a need for transmission reinforcement to serve contract customer growth in the Sarnia Industrial Line, Panhandle and Dawn Parkway systems, dependent on market conditions and ex-franchise transportation demands in Ontario, Quebec, the Maritimes and major U.S. natural gas consuming areas.

1.8.2 Pipe Condition and Strategy Overview

Asset Subclass	Avg. Age (Year)	Condition	Risk / Opportunity	Maintenance Strategy	Replacement / Renewal Strategy
TIMP Pipe	EGD RZ: 45 Union RZ: 45	These assets are in good condition. Pipelines are assessed through in-line inspections (ILI) and external corrosion direct assessment (ECDA). Corrosion features are prioritized for immediate or scheduled inspections and addressed within the timeline outlined in the TIMP (Transmission Integrity Management Program).	Risks identified for TIMP pipe: **Employee and Contractor Safety Risk and Public Health and Safety Risk**: Gas pipelines operating above 30% SMYS can rupture, leading to explosion. For lower stress pipelines, gas leaks and migration through underground infrastructure into buildings can result in gas accumulation and explosions. **Financial Risk**: Total repair costs, commodity loss, relighting customer gas appliances, regulatory penalties and any property damages caused by a gas leak **Operational Risk**: GHG emissions, environmental impact and extensive customer outages **Environmental Risk**: Greenhouse gas (GHG) emissions, environmental impact **Reputational Risk**: Unreliable service and customer outages	The maintenance strategy for TIMP pipe includes: • TIMP inspection program (ILI and ECDA) • Vital Main Damage Prevention program • Corrosion Control Operating Standard including cathodic protection (CP) survey • Leak Management Operating Standard including survey program conducted with defined frequency depending on material, age, CP protection and presence of wall-to-wall hard surface area • Valve Maintenance Operating Standard including inspection • Depth of Cover Survey program • Class Location Survey program • Easement Control Operating Standard including easement encroachment and easement clearing • MOP verification analysis	The replacement / renewal strategy for TIMP pipe includes: • Maintaining code compliance through replacement / renewal work identified by maintenance strategies • Maintaining code compliance and reduce risk by addressing immediate and scheduled digs as a result of ILI findings. • Retrofitting assets to continuously improve TIMP and migrate to ILI • Replacement of major pipelines as identified through condition and risk assessment findings
Distribution Steel Pipe (Pre-1971)	EGD RZ: 57 Union RZ: 57	Vintage steel mains have varying degrees of corrosion associated with material, coatings, design requirements, construction practices and maintenance practices based on standards used at the time. The condition methodology of distribution steel and plastic mains is common across its asset subclasses. The condition of these assets is determined through maintenance programs, condition assessment programs, tacit knowledge (SMA/worker input) and reliability modelling.	Risks identified for Distribution Steel and Plastic pipe: **Employee and Contractor Safety Risk and Public Health and Safety Risk**: Gas leaks and migration through underground infrastructure into buildings can result in gas accumulation and explosions. **Financial Risk**: Total repair costs, commodity loss, relighting customer gas appliances, regulatory penalties and any property damages caused by a gas leak **Operational Risk**: GHG emissions, environmental impact, service interruptions and reputational damages **Environmental Risk**: Greenhouse gas (GHG) emissions, environmental impact **Reputational Risk**: Unreliable service and customer outages	The maintenance strategy for distribution steel pipe includes: • Leak Management Operating Standard including survey program conducted with defined frequency depending on material, age, CP protection and presence of wall-to-wall hard surface area • Corrosion Control Operating Standard including CP survey • Valve Maintenance Operating Standard including inspection • Bridge Crossing Survey program • Watercourse Crossing Survey program • Vital Main Damage Prevention program (for vital main subset) • DIMP Asset Health Review (AHR) program • Condition assessment programs including distribution system integrity assessments and material fault reporting to identify and assess asset failure mechanisms	The replacement / renewal strategies to manage distribution steel pipe includes: • Bare and Unprotected Steel Pipe Replacement program • General Replacement program • Emergency Replacement program • Major discrete replacement project work • Corrosion Prevention program • Development of proactive strategies through integrity studies and sampling programs • Service Replacement program • Copper Services Replacement program • Relocation program (externally-driven)
Distribution Steel Pipe (Post-1970)	EGD RZ: 31 Union RZ: 36	Mains are in good condition, associated with adequate cathodic protection and good coating performance.			
Distribution Plastic Mains Modern Polyethylene (PE)	EGD RZ: 23 Union RZ: 17	These assets are considered to be in good condition. The materials and manufacturing processes support the longevity of this asset.		The maintenance strategies for distribution plastic pipe include: • Leak Management Operating Standard including survey program conducted with defined frequencies • Valve Maintenance Operating Standard including inspection • Watercourse Crossing Survey program • Condition assessment programs including integrity assessments and material fault reporting to identify and assess asset failure mechanisms	The replacement / renewal strategies to manage distribution plastic pipe includes: • Vintage plastic Aldyl A pipe proactive replacement program • AMP-fitting Replacement program • Service Replacement program • Emergency Replacement program • Relocation program (externally driven) • Development of proactive strategies through integrity studies and sampling programs
Distribution Plastic Mains Early Resins	EGD RZ: 38 Union RZ: 37				
Distribution Plastic Mains Vintage Plastic Aldyl A	EGD RZ: 44 Union RZ: 38	These assets are considered to be in good condition. However, the failure curve shows a rapid degradation over a very short period of time.			

1.8.3 Distribution Stations Condition and Strategy Overview

Asset Subclass	Avg. Age (Year)	Condition	Risk / Opportunity	Maintenance Strategy	Replacement / Renewal Strategy
Stations with Auxiliary Equipment	See **Table 5.3-3.**	Assets in the Stations with Auxiliary Equipment subclass are inspected and maintained on a regular basis in accordance with operating standards. At certain sites, the telemetry, pressure control and heating system components were found to have the following deficiencies: obsolescence, performance issues and non-standard configurations.	Risks identified for Stations with Auxiliary Equipment: **Employee and Contractor Safety Risk and Public Safety Risk**: Impact on surrounding population in the event of loss of containment **Financial Risk**: Commodity loss, repair costs and regulatory penalties **Operational Risk**: GHG emissions and loss of service to customers	The maintenance strategy for Stations with Auxiliary Equipment includes: • Facilities Integrity Management Program (FIMP) inspections • Pressure Control and Protection Inspection Standard • Equipment operating standards for auxiliary components	The replacement / renewal strategy for Stations with Auxiliary Equipment includes: • Stations with Auxiliary Equipment replacement strategy • Compliance remediation strategy • Obsolete heating equipment Strategy • Odourization strategy • Telemetry strategy • Stations retrofit strategy for Integrity pipe • Stations Capital Upgrade program • FIMP
Distribution System Stations	See **Table 5.3-5.**	Distribution system stations assets are inspected through field condition survey assessments to identify the existence of boot style regulators, below-ground installations, non-conforming configurations and vintage/obsolete components, which contribute to a higher potential of failures and operational issues. Distribution system stations have a relatively constant and low growth rate in failure events over the next 20 years based on the historical and current replacement and renewal programs. At this time, Union rate zone assets have not been incorporated in the Asset Health Review (AHR) program - a detailed plan is being developed for their inclusion.	Risks identified for Distribution System Stations and Customer Stations: **Employee and Contractor Safety Risk and Public Safety Risk**: Public impact, threat to over-pressuring customer piping **Financial Risk**: Repair and high maintenance costs, customer supply impact **Operational Risk**: Loss of service to customers	The maintenance strategy for Distribution System Stations and Customer Stations includes: • Distribution Integrity Management Program (DIMP) • Pressure Control and Protection Inspection Standard	The replacement / renewal strategy for Distribution System Stations includes: • Distribution System Station replacement strategy • Header Station Replacement program • Regulator and Relief program • Vaulted Stations Replacement program • Stations Painting program • Stations Capital Upgrade program • DIMP
Customer Stations	See **Table 5.3-7**.	Customer stations assets are inspected through field condition survey assessments to identify the existence of boot style regulators, below- ground installations, non-conforming configurations and vintage/obsolete components, which contribute to a higher potential of failures and operational issues. Customer stations are forecasted to have a slight increase in failure events with the current replacement pace over a 20-year projection.			The replacement / renewal strategy for Customer Stations includes: • Customer Station Replacement program • External Regulator Room program • Stations Painting program • Stations Capital Upgrade program • DIMP

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1.8.4 Utilization Condition and Strategy Overview

Asset Subclass	Avg. Age (Year)	Condition	Risk / Opportunity	Maintenance Strategy	Replacement / Renewal Strategy
Measurement Systems **200 and 400 Series Meters (<17 NCMH)** **>400 Series Meters (>17 NCMH)**	Dependent on meter type. Between: • 18-24 years old • 10-20 years old	Meter Exchange Government Inspection (MXGI) Program: This program is designed to replace meters before they fail. Meter seal life (and extensions) is based on sampling and testing to ensure Measurement Canada specifications are maintained. Non-program: Non-program meters that fail before the prescribed maximum service life are discovered during emergency calls or customer-initiated work. In most years, the number of meters exchanged outside of the program represents less than 1% of the population.	Failing to remove failed meters from service carries penalties under the *Electricity and Gas Inspection Act*, leading to: **Financial Risk**: Monetary penalty for non-compliance to government mandated programs and monetary loss due to shortened life cycle of meters, related to accreditation loss In addition, there is a financial opportunity to remove groups of meters that have been sampled multiple times with the availability of short extensions remaining.	The maintenance strategy for measurement assets is to continue with current maintenance standards at each rate zone until procedures and standards are aligned, targeted over the next two years. The joint Measurement Canada meter shop accreditation for both rate zones is targeted for 2022. Reactive maintenance (based on operating standards) is on an as-needed basis to address customer leaks and/or emergency calls.	The renewal strategy for measurement assets are as follows: For 200, 400 and >400 series meters covered under the MXGI program, the renewal strategy is to follow approved Measurement Canada programs. For >1000 series meters, meter exchanges are conducted one year prior to expiry as there is no sampling program in place. EGI reactively responds to customer leak or other service interruption calls for non-program related meter exchanges. In addition, EGI continues to use data to project MXGI replacement volumes with a focus on leveling volumes over future years. Meters have a complete set of data that includes quantity, age, make, size, location and historical performance. The completeness of this data enhances the optimization of the life cycle strategy.
Regulation, Safety and Piping Systems **<17 NCMH (200 and 400) Regulator Sets**	Dependent on meter and regulator type: between 20-30 years old. (~16% of the population is over 20 years old.)	Failure history and trending indicates that the wear-out phase for regulators associated with 200 and 400 series meters is unlikely to occur before 30 years of age. The failure rate is 0.14% of the total population.	Majority of customers are connected to the distribution system through 200 and 400 series regulator sets. Not maintaining these assets can lead to: **Employee and Contractor Safety Risk and Public Safety Risk**: Loss of containment, threat to over-pressuring customer piping, possibly leading to explosion **Financial Risk**: Repair, commodity loss, relights, potential property damage costs Failure of these assets primarily exposes EGI to financial risk.	The maintenance strategy for 200 and 400 series regulator sets is to proactively maintain units in conjunction with EGI's MXGI program. Reactive maintenance is on an as-needed basis (based on operating standards) to address customer leaks and/or emergency calls. EGI's MXGI Program, which covers all variations of meters and regulators, adheres to Measurement Canada requirements.	EGI's proactive replacement/renewal strategy for replacing 200 and 400 series regulator sets is to proactively exchange regulators as part of the MXGI program. Exchanging regulators during MXGI inspections prevents the population from reaching the wear-out phase. Run-to-failure is not an acceptable policy for this asset, as regulators are the last line of defense for over-pressure to the customer. Other compliance issues are corrected as part of MXGI work. 200 and 400 series regulator sets are opportunistically replaced if found to be 20 years or older.
Regulation, Safety and Piping Systems: **>17 NCMH (>400) Regulator Sets**	Dependent on meter and regulator type: between 20-30 years old.	>400 series regulator sets have an older population compared to 200 and 400 series regulator sets. For the EGD rate zone, more than half of these regulator sets have regulators older than 20 years. A sample survey identified sites not adhering to current installation specifications.	>400 series regulator sets account for 4.6% of all EGI regulator sets and are predominantly used in commercial, industrial, or higher density residential premises. The risks identified for >400 series regulator sets are the same as 200 and 400 series regulator sets. However, since delivery rates for > 400 series regulator sets are higher than delivery rates for the 200 and 400 series, the consequences are potentially greater and put a higher number of end users at risk.	The maintenance strategy for >400 series regulator sets is to adhere to a proactive and targeted inspection and remediation program, ensuring installation meets current code requirements in EGI operating standards. Reactive maintenance is on an as-needed basis to address customer leaks and/or emergency calls.	The proactive replacement/renewal strategy for >400 series regulator sets is to replace assets older than 20 years through the MXGI program. The Distribution Integrity Management Program (DIMP) leverages data on failure modes and frequencies to inform future maintenance strategies. EGI's proactive replacement/renewal strategy for replacing >400 series regulator sets is through: **Targeted Inspection and Remediation Program**: Sites identified with specific issues through integrity surveys will be remediated to ensure regulator sets are brought up to current installation standards. Similar to 200 and 400 series regulator sets, >400 series regulator sets are opportunistically replaced if found to be 20 years or older.
Regulation, Safety and Piping Systems: **Local First Cut Regulator Sets**	Dependent on meter and regulator type: between 20-30 years old.	Local first cut regulator sets in the EGD rate zone were surveyed for corrosion. Failure history and trending indicate the wear-out phase for regulators associated with 200 and 400 series meters is unlikely to occur before 30 years of age. First cut regulators were not historically replaced at the same time as second cut regulators, as per current installation standards. Sites not compliant with installation specifications are remediated.	These assets account for a very small percentage of the total population set and present higher consequences due to higher pressures managed by two pressure cuts. The risks identified for local first cut regulator sets are the same as 200 and 400 series regulator sets. However, these assets present a higher consequence than traditional single cut regulator sets due to the higher pressures managed by two pressure cuts.	The maintenance strategy for local first cut regulator sets is to proactively maintain units in conjunction with EGI's MXGI program. Reactive maintenance is on an as-needed basis to address customer leaks and/or emergency calls.	EGI's proactive replacement/renewal strategy for replacing local first cut regulator sets is through: **Regulator Exchange Program**: Proactively exchanging regulators as part of the MXGI program prevents the population from reaching the wear-out phase (the first cut regulator must be exchanged if the second cut is exchanged). Run-to-failure is not an acceptable policy for this asset, as regulators are the last line of defense for over-pressure to the customer. Local first cut regulator sets are opportunistically replaced if found to be 20 years or older.

Asset Subclass	Avg. Age (Year)	Condition	Risk / Opportunity	Maintenance Strategy	Replacement / Renewal Strategy
Regulation, Safety and Piping Systems: **Remote First Cut Regulator Sets (Farm Taps)**	Dependent on meter and regulator type: between 20-30 years old.	Remote first cut regulator set sites older than 15 years were determined to have more significant condition issues. First cut regulators are installed away from premises and near the property line, making them more susceptible to corrosion and third party damage. First cut regulators were not historically replaced at the same time as second cut regulators.	These assets account for a very small percentage of the total regulator set population. These regulator sets present a higher consequence due to the high pressures managed by the two pressure cuts. The risks identified for remote first cut regulator sets are the same as 200 and 400 series regulator sets. Remote first cut regulator sets present higher risks than 200 and 400 series regulator sets due to the higher pressures managed by the regulator.	The maintenance strategy for remote first cut regulator sets is to proactively maintain units in conjunction with EGI's MXGI program. Reactive maintenance is on an as-needed basis based on EGI operating standards to address customer leaks and/or emergency calls. Remote first cut regulator sets are included in the survey cycle of the Leak Survey program. Complete maintenance and inspections are performed based on operating standards.	For the EGD rate zone, a survey of 1700 remote first cut regulator sets was completed in 2017 to provide knowledge of asset condition. A risk assessment will be completed in 2020 to determine mitigation strategies. The proactive replacement/renewal strategy for replacing remote first cut regulator sets is through: **Inspection and Remediation Program**: Continue the comprehensive inspection program (including surveying all sites to categorize inventories) and remediate identified issues as required. **Regulator Exchange Program**: Proactively exchange regulators as part of the MXGI program. The first cut regulator must be exchanged if the second cut is exchanged. Run-to-failure is not an acceptable policy for this asset, as regulators are the last line of defense for over-pressure to the customer. Outside of MXGI work, regulators are replaced if found to be 20 years or older. For the Union rate zones, a 2020 survey of a sample of remote first cut regulator sets is planned and will provide initial knowledge on the asset subclass condition. As part of integration activities, an assessment program will be developed for these assets to better understand the condition of the broader population in both rate zones and to determine if further proactive processes or programs will be required to ensure safe and efficient operations.
Underground/Below-ground/Internal Piping Systems	N/A	**Service Extensions:** In the EGD rate zone, a sample survey of service extensions showed that some subsets have a population that requires cathodic protection. **Multi-Family Building Services:** In the EGD rate zone, EGI's Leak Survey program provides insight into the condition of multi-family building services assets. Generally, corrosion is found where the pipe intersects with the concrete wall–any severe corrosion that could affect safety is remediated. **Bulk Meter Headers:** EGI inspected bulk meter header sites in the EGD rate zone to understand condition and site factors. Common issues identified: • No clear demarcation points between EGI and customer assets • Obsolete regulators 20 years and older • Non-adherence to current installation and maintenance specifications • Vent clearances and configurations not met, not all fittings located above-ground and obsolete components A process to establish the population and determine condition will be aligned across the rate zones.	The risks identified are the same as 200 and 400 series regulator sets. • **Service Extensions**: since this piping enters the building below grade, gas leaks may have a higher chance of migration into the building, resulting in gas accumulation and a potential incident. • **Multi-Family Building Services**: since this piping system category is located inside high occupancy buildings, the potential consequence of failure is higher and a loss of containment will impact more people. • **Bulk Meter Headers**: since the building serviced are higher-occupancy units, there is potential for a higher consequence of failure. • The lack of clear demarcation between EGI and customer assets can further increase the risk of these headers. EGI is obtaining further information on these assets to better understand and manage asset risk.	The maintenance strategy for Underground/Below-ground/Internal Piping Systems assets is to continue to conduct Leak Survey and Cathodic Protection Survey programs based on operating standards through the DIMP. Reactive maintenance is on an as-needed basis to address customer leaks and/or emergency calls. Complete maintenance and inspections are performed based on operating standards.	EGI's replacement/renewal strategy for replacing service extensions is through: **Opportunistic Replacement**: Replace service extensions when the gas service is replaced and during planned city sidewalk/road replacements. **Continuation of Data Collection**: Sampling will be used to reassess risks and validate the feasibility of an above-ground inspection tool. EGI's replacement/renewal strategy for multi-family building services assets is through: **Replacement/Renewal**: Remediate high-priority condition issues identified through the Leak Survey and Cathodic Protection programs. For the EGD rate zone, EGI's replacement/renewal strategy for bulk meter headers is through: **Regulator Exchange Program**: Proactively exchange bulk meter headers as part of the MXGI program. **Delineation Definition**: Confirmation of a definitive delineation point between EGI and customer assets. All company-owned plant will be included in existing maintenance, replacement and renewal programs. **Inspection and Remediation Program**: Continuation of the targeted Leak Survey and Cathodic Protection programs. Outside of MXGI work, bulk header meters are replaced if found to be 20 years or older. The strategy for the Union rate zones will be determined following an inventory assessment of assets in this subclass.
Customer Owned Systems: **Customer-owned Piping and Appliances**	N/A	EGI inspects customer-owned assets at the time of initial installation and after conducting relights. Customers are issued A-tags if unacceptable conditions that present an immediate hazard are identified.	Improperly identifying customer-owned assets for maintenance can lead to the following risks: **Employee and Contractor Safety Risk and Public Safety Risk**: Loss of containment **Financial Risk**: Emergency response costs	The maintenance strategy for customer-owned assets is to continue using existing operating standards at initial installation. Reactive maintenance is on an as-needed basis to address customer leaks and/or emergency calls.	The current strategy for customer-owned systems is to continue existing practices at initial installation. For any subsequent issues, the customer is responsible to take corrective action.

1.8.5 Storage and Transmission Operations (STO) Condition and Strategy Overview

Asset Subclass	Ave. Age (Year)	Condition	Risk / Opportunity	Maintenance Strategy	Replacement / Renewal Strategy
Compression **Dehydration** **Liquefied Natural Gas (LNG)**	30 35 50	Asset condition is primarily assessed based on a preventive maintenance (PM) program comprised of rigorous inspections. For engines and compressors, operating hours since the previous overhaul are the primary indicator of condition. Age is also considered as a condition indicator in terms of reliability and obsolescence. A reliability assessment through the Asset Health Review was conducted on all Storage Corunna (SCOR) compressors in the EGD rate zone to determine asset condition.	Not maintaining compression, dehydration and LNG assets pose the following risks: **Operational Risk**: Potential failure can lead to equipment damage or reliability concerns. Unplanned unit failures, especially during late season withdrawal, can negatively impact customers' gas supply costs. **Employee and Contractor Safety Risk and Public Safety Risk**: The safety risk related to loss of containment from the compressor units is considered, however, the chance of a significant leak is low. Safety systems reduce the chance of an escalation even further. **Financial Risk**: Compressor failures result in unexpected repair costs and frequently involve collateral damage. New regulatory requirements could potentially limit the use of compression equipment until compliance is achieved.	The maintenance strategy for compressor, dehydration and LNG is based on a combination of Original Equipment Manufacturer (OEM) recommendations as well as the output of techniques such as Reliability-Centered Maintenance (RCM) and subject matter advisor (SMA) expertise: • Condition-based maintenance is used in many cases. A detailed inspection routine at set frequencies is established specific to a particular unit (components replaced as required). • Preventive maintenance activities are scheduled on a set frequency to restore asset performance. Condition monitoring of auxiliary equipment (pumps/motors, etc.) and control systems is ongoing.	The renewal strategies for compressors, dehydration units and LNG assets is as follows: • Overhauls as recommended by the OEM (hour-based) • Overhauls recommended by SMAs based on condition findings • Planned obsolescence based on design life and historical obsolescence (largely dependent on vendor equipment support) • Risk- and compliance-driven replacement
Underground Storage	35.5	Well condition is assessed directly by the Storage Downhole Integrity Management Program (SDIMP) using casing inspection logs. Condition assessments for wells are based on abandonment criteria prescribed by *CSA Z341* and the *Oil, Gas and Salt Resources (OGSR) Act*. Condition assessment is based on directly measured casing inspection data. Reliability modelling estimates the well wall loss growth rate by extrapolating the historical measured growth rate and predicting when the wall loss will exceed tolerances.	Not maintaining EGI gas wells poses the following risks: **Employee and Contractor Safety Risk and Public Safety Risk**: Loss of containment can pose a risk to public and worker safety. **Financial Risk**: Wells represent significant financial risk to EGI and regulated customers. Unexpected well failures carry a large replacement cost and incur product loss. Reduced reservoir performance may drive up gas supply costs.	The maintenance strategy for gas wells is as follows: • Monitor surface and downhole well conditions to ensure the continued integrity of the storage well system including the emergency shutdown valves (where applicable), master valve, wellhead and casings. If a problem is identified, the well is repaired or abandoned. • Continue with transient pressure testing to identify wells that could benefit from acid stimulation to maintain deliverability. • Continue well inspection as per *CSA Z341* and the OGSR Act. • Develop a long-term strategy for cathodic protection on well assets.	The renewal strategies for wells are as follows: • Relining wells • Replacing top two casings • Drilling new wells to replace abandoned well(s) • Wellhead and emergency shutdown valves replacement based on condition • Risk- and compliance-driven replacement
Pipelines	The overview of asset condition and strategy for transmission pipelines is discussed in **Section 5.2.4**. The overview of strategy for transmission pipelines reinforcement is discussed in **Section 5.1.4**.				

1.8.6 Real Estate and Workplace Services (REWS) Condition and Strategy Overview

Asset Subclass/Program	Ave. Age (Year)	Ownership	Condition	Risk / Opportunity	Maintenance Strategy	Replacement / Renewal Strategy
Properties (Buildings / Land)	N/A	Owned and leased	Facility assessments were conducted on EGI properties, based on a defined set of standards representing industry best practices relating to exterior site works, architectural elements, interiors, furniture and amenities. Using the Functional Obsolescence or Adequacy Index (AI), a condition index tool used to illustrate the functional condition of the asset. The Facility Condition Index (FCI), a generally-accepted industry benchmarking tool was also used. All EGI properties were inspected for the purpose of calculating an FCI and creating a long-term capital plan. See **Table 5.6-3** for the condition findings for each property.	**Employee and Contractor Safety Risk**: Facilities with operational deficiencies pose a safety risk to employees and hinder execution of tasks. Some facilities have inadequate operations yard and administrative parking. The mix of industrial and employee vehicles is a potential contributor to motor vehicle incidents. **Financial Risk**: EGI faces financial risk if properties are not maintained, hindering operations and administrative functions. Some facilities use more energy than a comparable renovated facility (utilizing current Ontario Building Code (OBC) and energy standards). Inadequate site configuration and lack of office and support areas hinder operations and administrative functions. Older buildings have high greenhouse gas emissions and uses more energy than a comparable new construction.	A preventive maintenance strategy is in place to ensure asset performance and to reduce the risk of failure or degradation of performance in supporting occupants.	The strategies for the Properties asset subclass were developed to align with business requirements and the OBC as well as to correct deficiencies on site: • Renovating existing facilities • Building new facilities • Disposing of current site and relocating to a new site • Continuing maintenance of the current site Choosing the appropriate strategy is based on a combination of physical/functional assessments and support of the business strategy.
Workplace Furnishings	N/A	Owned	Workspaces at each site consist of workstations and office furniture. These furnishings are either considered current (meeting EGI standards) or legacy (not meeting current standard). Current EGI furniture standards provide: • Ergonomic support • Daylight and views for building occupants through the use of mid-height panel systems • Task seating to address a range of body types • Consistent workstation configuration • Lower operating costs by contributing to fixed environments that allow a broad range of administrative requirements without change.	**Employee and Contractor Safety Risk**: Legacy furnishings do not meet current ergonomics standards; therefore, employees are more likely to suffer from repetitive strain injuries and other ailments stemming from decreased access to light. **Financial Risk**: Legacy furnishings approaching 30 years old result in productivity reductions and increased maintenance costs.	N/A	The strategy for the Workplace Furnishings asset subclass is to replace office and meeting room furnishings as required. Remaining legacy office, meeting room and ancillary furnishings are replaced with current standard systems as building life cycle renewal is executed. Ergonomic modifications and tools are issued as recommended to prevent repetitive strain injuries and accommodate return-to-work employees. .
Building Systems Program	N/A	N/A	A third-party engineering consulting company was employed by EGI to analyze factors such as age of equipment, maintenance records, repair cost, building standards and compliance issues to determine overall risks and the replacement timing of heating, ventilation, air conditioning (HVAC) equipment, plumbing, electrical systems, building envelope, facilities equipment and exterior site improvements.	**Financial Risk**: If building systems are not properly maintained, there is financial risk to EGI as the failure of these systems increases substantially, which can potentially lead to loss of use and decreased staff productivity.	N/A	The replacement/renewal strategy for building systems assets is to maximize the useful life of equipment and replace building systems before failure, including the replacement of the building envelope, HVAC and electrical systems to current environmental standards, ensuring interior comfort and overall security.
GHG Energy Reduction Program	N/A	N/A	EGI has started a third-party study on energy efficiency and emissions for its office buildings. The study identifies operational improvements needed to ensure building systems are operated efficiently to reduce natural gas use.	Existing facilities use more energy than a comparable new or renovated facility (using current OBC and energy standards). Existing facilities emit more greenhouse gases that can potentially affect ratepayers. **Energy Efficiency Opportunity**: Reduction in operating costs or GHG emissions	N/A	Existing building commissioning at locations not planned for improvements in the five-year plan will be reviewed or recommissioned through a third party to identify a mix of measures with a range of implementation costs and energy/greenhouse gas savings. Once completed, measures, findings and an action plan to measure energy conservation implementation will be developed, as well as verification and ongoing commissioning, which will include operational and capital improvements. Lessons learned will be implemented on future initiatives.
Micro-Operations Depot Revitalization Program	N/A	Owned and leased	There are 18 micro-operations depots located in the Northern region that are on average over 50 years old, consisting of 17 owned and one leased property. The sites are in aging physical condition and do not meet required functionality.	**Financial Risk**: Risks include the financial impact of low utilization or functionally and physically deficient assets. **Employee and Contractor Safety Risk**: Current physical conditions pose a hazard to employee safety. Legacy buildings with obsolete systems have high GHG emissions and use more energy than a comparable new construction.	N/A	The strategy is to renovate or replace 14 identified target micro-operations depot sites. Renovations or replacement will include the building envelope, HVAC and electrical systems. Compliance to environmental standards, building codes, accessibility and overall security are major considerations to ensure safe and reliable operations.

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1.8.7 Fleet and Equipment Condition and Strategy Overview

Asset Subclass		Avg. Age (Year)	Condition	Risk / Opportunity	Maintenance Strategy	Renewal / Replacement Strategy
FLEET	**Light-Duty Vehicles**	5.3 (EGD RZ) 4.5 (Union RZ)	Analysis indicates that average maintenance costs exceed the market value of a light-duty vehicle at an approximate age of five to seven years or 160,000 kilometres, depending on the vehicle's weight class.	**Financial Risk**: Aging fleet vehicles primarily pose a financial risk to EGI if they are not maintained or replaced as needed. Maintenance costs increase beyond the vehicle value and productivity may be impacted due to increased downtime as a result of more frequent unplanned maintenance activities.	Vehicle maintenance every 8,000 kilometres (approximately every three months)	**Light Duty Vehicle (LDV) Replacement Strategy**: this proactive program replaces vehicles based weight class, mileage and assessed condition. The replacement schedule is as follows: • Class 1 Vehicles – 60 months • Class 2 Vehicles – 72 months • Class 3 Vehicles – 84 months The average replacement age for LDVs is 6 years and the optimal average age for the asset pool (the midpoint of the average replacement) is calculated at 3 years.
	Medium-Duty Vehicles	9.3 (EGD RZ) 5.2 (Union RZ)	Analysis indicates that average maintenance costs exceed the market value of a medium-duty vehicle at approximately seven to 12 years old or 175,000 kilometres, depending on the vehicle's weight class.		Vehicle maintenance every 10,000 kilometres or 500 engine hours (approximately every four months)	**Medium Duty Vehicle (MDV) Replacement Strategy**: this proactive program replaces vehicles based on weight class, mileage and assessed condition. The replacement schedule is as follows: • Class 4 Vehicles – 84 months • Class 5 Vehicles – 120 months • Class 6 Vehicles – 144 months The average replacement age for MDVs is 9.7 years and the optimal average age for the asset pool is calculated at 4.85 years.
	Heavy-Duty Vehicles	7.6 (EGD RZ) 8.1 (Union RZ)	Analysis indicates that average maintenance costs exceed the market value of a heavy-duty vehicle at 12 years old or 350,000 kilometres, depending on the vehicle's weight class.		Vehicle maintenance every 10,000 kilometres or 500 engine hours (approximately every four months)	**Heavy Duty Vehicle (HDV) Replacement Strategy**: This proactive program replaces vehicles based on weight class, mileage and assessed condition. The replacement schedule is as follows: • Class 7 Vehicles – 144 months • Class 8 Vehicles – 144 months The average replacement age for HDVs is 12 years and the optimal average age for the asset pool is calculated at 6 years.
Heavy Equipment		10.7 (EGD RZ) 7.9 (Union RZ)	Analysis indicates that average maintenance costs exceed the market value of heavy equipment at approximately 12 years old.		Equipment maintenance is conducted on a scheduled basis, ranging from three to 12 months, depending on the type of equipment.	**Heavy Equipment Replacement Program**: this proactive program is based on average historical spending and is driven by: • Proactively replacing assets based on a detailed physical condition assessment • Acquiring net new equipment based on business needs.
Tools		N/A	The general condition and functionality of tools are assessed by the operator prior to use and during scheduled inspections and calibrations.	Aging, broken, or inadequate tools pose the following risks: **Financial Risk**: Increased maintenance costs and lower productivity **Employee and Contractor Safety Risk and Public Health and Safety Risk**: Increased employee, contractor and customer safety and health risks if tools are not in good condition **Operational Risk**: Service and/or emergency response reliability	N/A	**Tools Replacement Program**: this reactive program is in place to address tools that are: • Showing signs of wear and tear, broken and/or unrepairable • Stolen or lost • Declared obsolete by the manufacturer or supplier • No longer approved for use due to updated Engineering standards and practices • Needed and requested by EGI operating departments to perform their business functions

1.8.8 Technology and Information Services (TIS) Condition and Strategy Overview

Asset Subclass	Avg. Age (Year)	Condition	Risk / Opportunity	Maintenance Strategy	Replacement / Renewal Strategy
Laptops and Desktops	2	Laptops and desktops tend to experience performance issues and failures in their fourth year of operation (constituting approximately 30% of these assets). The condition of laptops and desktops is not proactively monitored.	**Financial Risk**: Aging assets result in a reduction in productivity and increase in maintenance costs.	Laptops are replaced proactively based on age and warranty status.	**Laptop/Desktop Renewal Strategy**: EGI's strategy is to replace laptops and desktops every four years. For the majority of their life (three years), these assets are under warranty. This strategy allows for a short extended use of the asset past warranty expiration (one additional year) prior to replacement.
Desktop Sustainment Equipment	N/A	The condition and health of desktop sustainment equipment is not proactively monitored.	**Employee and Contractor Safety Risk**: Inadequate desktop sustainment equipment compromises the health and safety of employees who require specific equipment for ergonomic purposes. **Financial Risks**: Inability to meet business needs and requirements, reducing overall productivity **Operational Risk**: Inadequate or lack of desktop sustainment equipment required for new and existing employees	Reactive maintenance as required through service requests.	**Desktop Sustainment Equipment Strategy**: Desktop sustainment equipment is provided on an as-needed basis. The replacement of desktop sustainment equipment is based on the following circumstances: • Equipment is damaged, broken, or malfunctioning. • Equipment is required based on employee ergonomic assessments. • Equipment is required for new employee and contractor hires.
Core and Security Infrastructure	3	Servers and appliances tend to experience performance issues and failures in their fifth year of operation (constituting approximately 30% of these assets).	**Financial Risk**: Aging assets result in a reduction in productivity, a risk of increase in hardware incidents and outages and an increase in maintenance costs.	Servers and appliances are replaced proactively based on age, compliance and warranty status.	**Core Infrastructure and Security Renewal Strategy**: EGI's strategy is to replace servers and appliances for core infrastructure and security every five years. For the majority of their life (four years), these assets are under warranty and this strategy allows for a short extended use of the asset past warranty expiration (one additional year) prior to replacement.
Packaged and Developed Applications	10	The condition of packaged and developed applications is evaluated on the following: • Ability to meet business requirements • Hardware to meet vendor support requirements • Software to meet vendor support life cycle (for packaged applications) • Ability to enhance and support existing applications See **Table 5.8-3** and **Table 5.8-4** for the condition findings for this subclass.	**Financial Risks**: • Inability to meet business needs and requirements, reducing overall productivity • Inability to meet financial and reporting compliance requirements • Increased maintenance costs due to reactively addressing required software and hardware repairs **Operational Risk**: Extended application and system outages. **Reputational Risk**: cybersecurity exposure due to the inability to apply required security patches may potentially lead to negative reputational impacts for EGI if any breaches occur.	Maintenance releases and software defect fixes are rolled out regularly as a means of reactively maintaining the performance of packaged and developed applications.	**Developed and Packaged Applications Renewal Strategy**: The replacement of developed and packaged applications is dependent on changing business requirements or due to an application solution becoming unsupported by its vendor.
Application Infrastructure Software	12	The condition of application infrastructure software is evaluated on the following: • Software to meet vendor support refresh life cycles • Ability to support the key foundational software required for in-use/predicted applications See **Table 5.8 5** for the condition findings for this subclass.		Maintenance is reactive - performance issues or software defects are addressed as they are identified.	**Application Infrastructure Renewal Strategy**: A proactive replacement/refresh strategy is in place, driven by forecasted changes to existing software products and business requirements.
Mobile Devices	2	The condition of mobile devices is not proactively monitored.	**Employee and Contractor Safety Risk; Public Health and Safety Risk**: Inadequate (or the lack of) mobile devices hinder the ability of employees to respond to emergency field situations, which may contribute to the severity of an incident and potentially endanger lives of the public. **Operational Risk**: Inadequate (or the lack of) mobile devices hinder the ability of employees to resolve off-hours, on-call situations, which may affect the reliable and safe operations of EGI's systems and networks.	Mobile devices are maintained internally to address performance issues. Damaged devices are repaired/replaced on an as-needed basis within the three-year replacement window.	**Mobile Device Renewal Strategy**: EGI follows industry best practices for replacing mobile devices at two to three years, which aligns with the smartphone manufacturers' release cycles and typical data plan contracts.
Field Devices	4	The condition of field devices is not proactively monitored. Due to exposure to tough working conditions, field devices experience significant wear and tear. (Breakage and performance issues generally occur in their fourth year of use).	**Employee and Contractor Safety Risk; Public Health and Safety Risk**: Inadequate (or the lack of) field devices hinders the ability of employees to respond to emergency field situations due to device unavailability **Operational Risk**: Inadequate (or the lack of) field devices may result in increased time travelling between office and job sites.	Maintenance repairs and replacements are performed as needed through service requests.	**Field Device Renewal Strategy**: Most field devices, such as ruggedized laptops, Toughbooks and Toughpads, have a four-year proactive replacement strategy driven by industry best practices. Some assets, such as truck modems, are replaced as needed.

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1.9 Capital Expenditure

The EGI capital plan was optimized from 2021 to 2025 using the Asset Management Core Process (outlined in **Section 4.2**). The result addresses the organization's asset needs and includes known risks and opportunities requiring action over the next five years.

In total, 1,251 Union rate zone investments and 863 EGD rate zone investments were included in the optimization of the five-year plan. Separate optimizations were run for each rate zone.

In preparation for optimization, comprehensive governance reviews were completed on proposed investments using the following criteria:

- Investment scope met EGI's capitalization policy.
- Investments presented a well-articulated purpose, need and timing aligned with asset class objectives and life cycle management strategies.
- Investment scope definition and alternatives adequately addressed project risks and/or opportunities.
- Investments supported the asset management principles of balancing risk, cost and performance.
- Execution risks were reasonable (resource capacity).
- Initiatives identified as mandatory were justified, based on:
  - Compliance requirements
  - Exceeding a risk limit within EGI's intolerable risk region or Very High risks on the Enbridge Risk Matrix (**Figure 4.1-7**)
  - Third-party relocation driven
  - Program work with sufficient history and risk to warrant continuation
  - Growth work that met the requirements of *EBO 188* or *EBO 134*

1.9.1 Capital Considerations

The optimization process is based on EGI management setting a capital constraint or threshold from which a portfolio of work driven by asset needs is defined. The capital constraint is determined based on the defined regulatory framework and asset class objectives and strategies. Determining the capital constraint involves EGI's Asset Management, Finance and Regulatory departments.

To complete EGI's latest portfolio optimization, the outcome of the MAADs Decision *(EB-2017-0306/EB-2017-0307)* and smoothing the impact to ratepayers were considered when establishing the capital constraint. The MAADs Decision established the Regulatory framework and provided EGI with the approved five-year (2019-2023) annual Incremental Capital Module (ICM) Materiality Threshold, giving EGI access to rate recoveries for qualifying incremental capital investments over and above this Materiality Threshold through the OEB's Incremental Capital Module. The 2021 ICM Materiality Threshold formula was used to determine EGI's capital constraint for 2021. For the years 2022 to 2025, the capital constraint was escalated based on the projected growth factor, allowing EGI to balance rate impacts with the utility's obligation to serve and maintain its plant. The capital constraint is inclusive of overheads[2].

EGI's capital spend requirements up to the OEB-approved ICM Materiality Threshold is described as Base Capital. To understand which projects would be considered incremental and potentially ICM-eligible, EGI applied descriptions of Base Capital and Incremental Capital to all investments for optimization (**Table 1.9-1**):

Table 1.9-1: Base Capital and Incremental Capital Descriptions

Term	Description
Base Capital	• Represents the ongoing capital requirements of the utility to maintain safe and reliable operations and to economically attach new customers and pursue opportunities for innovation • Driven by asset class strategies and programmatic work that has sufficient history and risk to warrant continuation • Supported by existing rates (through depreciation expense, annual Price Cap Index rate increases, or incremental revenues from customer growth)

[2] *Overheads include loadings, Interest During Construction and departmental and labour costs.*

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Term	Description
ICM-eligible Capital	• Represents discrete projects requiring a total in-service capital investment of over $10M • Refers to spend driven by asset class strategies and not supported by existing rates • Total incremental spend will include all capital costs associated with the identified project incurred up to the project's in-service year when ICM is requested. ICM eligibility does not confirm that EGI will seek ICM recovery for these projects.

To optimize the 1,251 Union rate zone and 863 EGD rate zone investments, the asset investment planning tool (C55) was used. The capital constraint values were used to set an overall constraint and the optimal capital timing was determined for proposed investments.

1.9.2 Optimization Results

Portfolio optimization considers the previously approved plan; the initial spend profile is the result of the previous optimization and approved portfolio, with the addition of new investments and updates to existing investments.

Figure 1.9-1 and **Figure 1.9-2** present the five-year capital requirements by asset class, with five years of historical spend. For the EGD rate zone, the capital requirements to meet asset class objectives and life cycle management strategies, while managing risk, exceed the capital available for optimization in most years. For the Union rate zones, the capital requirements exceed the capital constraint for all years. The capital that exceeds the capital constraint can be considered as ICM-eligible capital per the definition in **Table 1.9-1**. The final five-year portfolio of spend was reviewed and approved by the Vice President of Engineering and the Asset Management Steering Committee.

The asset plan spend profile was also reviewed from a perspective of in-service capital in relation to the materiality threshold to determine potential ICM-eligible project requests.

Note: The total forecasted capital expenditures categorized by asset class depicted in **Figure 1.9-1** and **Figure 1.9-2** are comprised of each investment's direct costs and the associated overheads. Asset class historical spend profiles do not include associated overheads; for this reason, overheads are identified as a separate category historically.

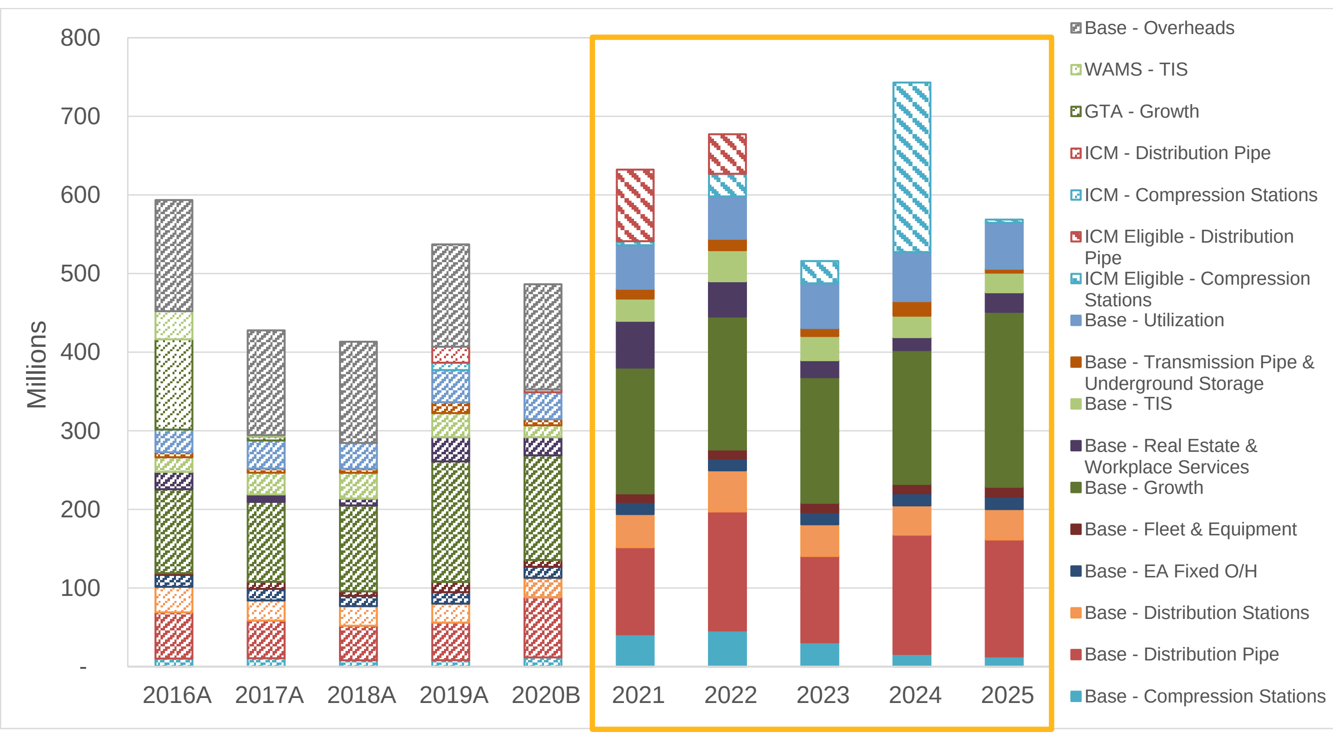

Figure 1.9-1: Final Five Year Plan by Asset Class (with ICM) – EGD Rate Zone (Capital Expenditure)

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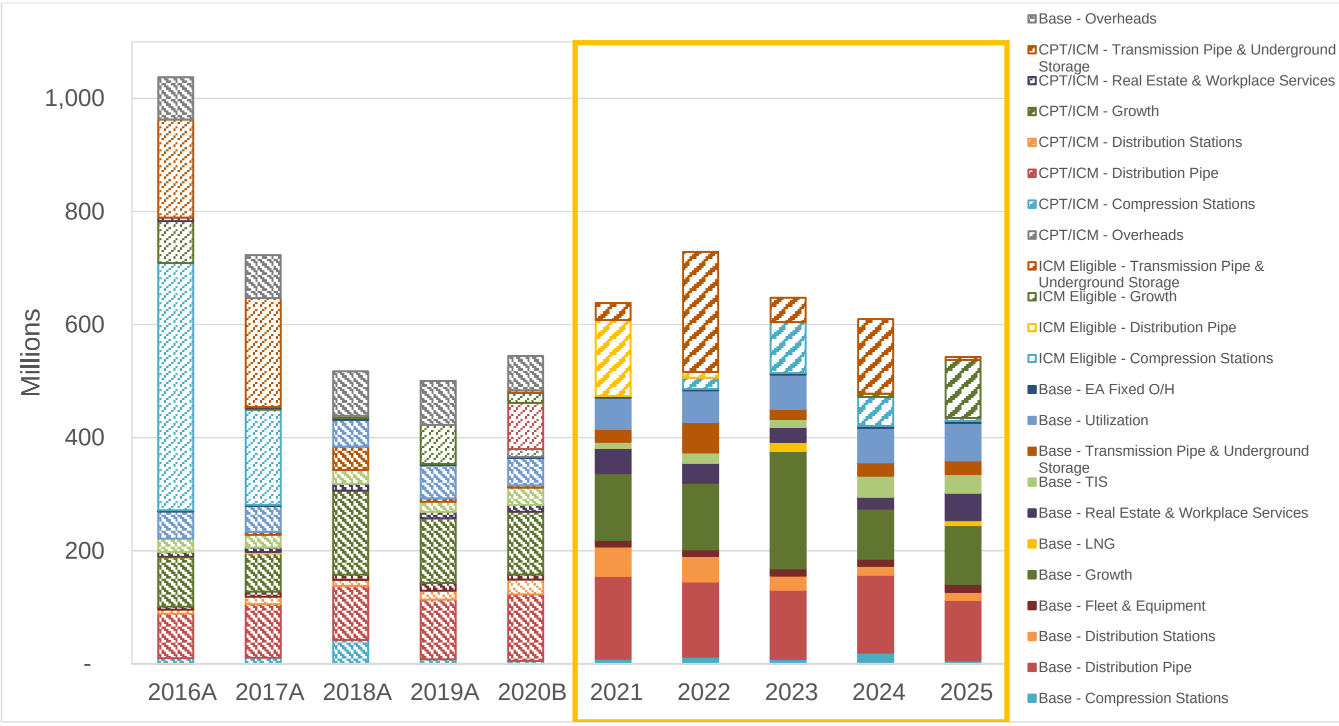

Figure 1.9-2: Final Five Year Plan by Asset Class (with ICM) – Union Rate Zones (Capital Expenditure)

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Table 1.9-2 and **Table 1.9-3** list the ICM-eligible capital projects by rate zone. Investment costs do not include overheads.

Table 1.9-2: ICM-Eligible Capital Projects – EGD Rate Zone

Asset Class	Project Name	In-Service Year	2021-2025 Net Capital ($M)	Total Net Capital ($M)	Driver
Distribution Growth	Rideau Reinforcement	2025	52.7	53.5	Mandatory: Reinforcement Specified per Network Analysis
	York Region Reinforcement	2026	25.9	65.8	Mandatory: Reinforcement Specified per Network Analysis
	Amaranth System Reinforcement	2024	10.3	10.3	Mandatory: Reinforcement Specified per Network Analysis
	Thornton Reinforcement	2023	10.9	10.9	Mandatory: Reinforcement Specified per Network Analysis
Distribution Pipe	NPS 20 Lake Shore Replacement (Cherry to Bathurst)	2022	103.4	104.7	Condition
	St. Laurent Phase 3[13] St. Laurent Plastic - Montreal to Rockcliffe St. Laurent Plastic - Coventry/Cummings/St Laurent St. Laurent Plastic - Lower Section	2021	12.4	12.4	Condition
	NPS 12 St. Laurent Aviation Pkwy[3]	2022	29.5	29.8	Condition
	NPS 12 St. Laurent Queen Mary/Prince Albert[13]	2022	11.0	11.1	Condition
	NPS 12 Martin Grove Rd Main Replacement: Lavington to St. Albans Road	2024	18.3	18.3	Condition
	NPS 10 Glenridge Avenue, St. Catharines	2025	11.8	11.8	Condition
Distribution Stations	Harmer District Station	2022	13.1	13.1	Compliance and ILI requirements
Compression Stations	SCOR: K701/2/3 Reliability - Replacement	2024	185.2	185.2	Obsolescence
	Dehydration Expansion	2023	41.0	41.0	Condition; Growth

[3] *The St. Laurent portfolio of work consists of four phases of work and each phase is comprised of separate projects. Phases 1 & 2 have been previously completed, with Phases 3 & 4 remaining in this forecast period. Phase 3 includes the following investments: Three PE main investments in 2021 including Lower Section, Coventry/Cummings/St Laurent and Montreal to Rockcliffe. Phase 4 includes the following investments: NPS 12 St. Laurent Aviation Pkwy and NPS 12 St. Laurent Queen Mary/Prince Albert in 2022. The investments comprising Phases 3 & 4 will be combined in a single Leave to Construct application that will be submitted in Fall 2020.*
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Asset Class	Project Name	In-Service Year	2021-2025 Net Capital ($M)	Total Net Capital ($M)	Driver
	SCOR: Meter Area-Upgrade	Ph 1 - 2021 Ph 2 - 2022	34.2	45.5	Condition
	Storage Crowland (SCRW): Station-Renewal In-Place	2025	27.9	27.9	Obsolescence
Transmission Pipe and Storage	Crowland Pool (PCRW): Wells-Upgrade	2026	1.7	11.7	Compliance, Condition
REWS	Kennedy Road Expansion	2023	15.0	26.3	Condition
	Station B New Building	2021	15.5	17.6	Condition, Function, In Progress
	SMOC/Coventry Facility Consolidation	2023	30.8	30.8	Function and Service Coverage Duplication
	Kelfield Operations Centre	2023	10.8	10.8	Condition, Function
	VPC Core and Shell	2025	20.0	20.0	Condition

Note: Dismantlement costs are not included in Total In-Service Capital.

Table 1.9-3: ICM-Eligible Capital Projects – Union Rate Zones

Asset Class	Project Name	In-Service Year	2021-2025 Net Capital ($M)	Total Net Capital ($M)	Driver
Distribution Growth	Customer Stratford Reinforcement	2022	13.3	13.3	Mandatory: Reinforcement Specified per Network Analysis
	Dunnville Line Reinforcement (6.3 km of NPS 10)	2022	9.1	9.1	Mandatory: Reinforcement Specified per Network Analysis
	NBAY: Parry Sound Lateral Reinforcement (12.5 km of NPS 6)	2023	15.0	15.0	Mandatory: Reinforcement Specified per Network Analysis
	WATE: Owen Sound Transmission System, Reinforcement (28.8 km of NPS 16)	2025	81.7	83.6	Mandatory: Reinforcement Specified per Network Analysis
	LOND: Goderich Transmission System, Reinforcement (11.4 km of NPS 10)	2026	2.2	25.0	Mandatory: Reinforcement Specified per Network Analysis
	Ingersoll Transmission Station Rebuild	2022	8.4	8.4	Mandatory: Reinforcement Specified per Network Analysis

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Asset Class	Project Name	In-Service Year	2021-2025 Net Capital ($M)	Total Net Capital ($M)	Driver
	SUDB: Marten River Compression Reinforcement	2023	51.6	51.6	Mandatory: Reinforcement Specified per Network Analysis
Distribution Pipe	NPS 8 Port Stanley Replacement	2024	20.6	20.6	Condition
	INTE: North Shore - Section A: Retrofit ECDA to ILI	2021	12.0	12.3	Mandatory: Retrofit for TIMP program (ILI Compliance)
	LOND - London Lines Replacement	2021	106.2	110.3	Condition
	Kirkland Lake Lateral Replacement	2022	16.8	16.8	Condition
Compression Stations	Dawn Plant-C Compression Life Cycle	2024	131	131	Obsolescence
	Waubuno Compression Life Cycle	2024	12.9	12.49	Obsolescence
Transmission Pipe and Storage	Panhandle Line Replacement	2023	29.8	29.8	Condition, High Consequence
	INTE: Dawn - Cuthbert - ECDA to ILI Retrofit NPS 42, 34, 26	2022	24.6	25.0	Mandatory: Retrofit for TIMP program (ILI Compliance)
	Dawn Parkway Expansion (Kirkwall-Hamilton NPS 48)	2022	176.1	181.7	Growth
	Sarnia Expansion (NPS 20 Dow to Bluewater)	2021	19.2	20.5	Growth
	Sarnia Expansion (Novacor Station)		6.5	6.5	
	Sarnia Expansion - Bluewater Energy Park (Asset #1)	2024	64.5	64.6	Growth
	Sarnia Expansion Project- Bluewater Energy Park (Customer Station)		11.7	11.7	
	Sarnia Expansion - Bluewater Energy Park (Asset #2)		34.0	34	
REWS	Thunder Bay Regional Operations Centre	2025	10.2	10.2	Condition
	New Site No. 4	2023	28.8	28.8	Operations Site Consolidation

Note: Dismantlement costs are not included in Total In-Service Capital.

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1.10 Assumptions

The five-year capital plan is based on the best available information at the time of completion. Key assumptions detailed in the tables below provide a basis for interpretations.

Table 1.10-1: Assumptions for All Categories

Assumption	Basis for Assumption
Optimization results are based on available information as of April 2020.	Based on EGI's Portfolio Optimization process, the portfolio of spend is determined through the completion of C55 leveling and subsequent reviews. Results are based on best available information and COVID impacts have been incorporated where they are understood through these reviews.
Future costs are valued at 2020 Present Value.	Current practice forecasts projects based on 2020 rates. An annual inflation factor of 2.0% was applied to programs with defined scope/unit rates (such as meter purchases, customer growth and service relays).
All cost estimates are based on available information as of April 2020.	Using EGI's Value-Based Asset Management Model, these requirements will be reviewed and revised as required.
All risk assessments are based on risk models and methodology as of April 2020.	Using EGI's Value-Based Asset Management Model, the risk management framework will be reviewed and revised as required.
Projects in flight that span over multiple years must continue until complete.	Once a project is in progress it is inefficient and costly to terminate.
Historical actual costs are valued at years' actual value.	Historical values are not adjusted to be expressed in present value.

Table 1.10-2: Renewal Assumptions

Assumption	Basis for Assumption
Asset health provides a reasonable representation for asset condition and remaining asset life for forecasting purposes.	Where possible, reliability engineering is used to understand asset health. Based on projected life cycles, consequences of failure, tacit knowledge and asset data, risk is quantified. Renewal projects are planned to reduce this risk to the lowest practicable level.

Table 1.10-3: Customer Growth Assumptions

Assumption	Basis for Assumption
Customer growth is forecasted using historical trends and economic projections for the planning period.	The customer growth forecast considers new housing starts, meetings with builders and developers, municipal growth forecasts, general economic indicators and projections provided by specialized external consultants to combine localized trends with macro-economic factors.
Load forecasting is based on current understanding of temperature inputs and estimated customer consumptions.	EGI is cognizant that there may be impacts to customer growth forecasts based on climate/carbon policies. EGI currently has Demand Side Management (DSM) programs in place for our customers. Historical DSM is built into the load forecast based on past results. Should Integrated Resource Planning (IRP) drive more load reduction programming as a result of the IRP Policy Proposal (*EB-2020-0091*) and subsequent planning activity, impacts would be factored into future Asset Management Plans.

Table 1.10-4: Solution Planning Assumptions

Assumption	Basis for Assumption
Budgeting and forecast are determined through the solution planning process.	Estimates are determined considering region and work type to accurately forecast. Appropriate project planning processes are followed.

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2. Introduction

2.1 Purpose of the Asset Management Plan

On January 1, 2019, Enbridge Gas Distribution (EGD) and Union Gas Limited (UGL) amalgamated to form Enbridge Gas Inc. (EGI). EGI is comprised primarily of natural gas utility assets and operations that serve over 12 million consumers with 3.7 million residential, commercial and industrial connections in Ontario, serving over 355 municipalities and 21 First Nation communities. EGI's 280 billion cubic feet (approximately five billion cubic metres) of storage assets are tied to large and growing demand centres in Canada and the U.S. and provide a critical link to low-cost natural gas supplies. The management of these assets is important for the safe and reliable delivery of natural gas to customers. Asset management at EGI ensures that value is realized through its assets while managing risk and opportunity.

The purpose of this Asset Management Plan (AMP) is to outline:

- Policy and strategies for establishing effective asset management for all utility assets within EGI's regulated operations
- Process and governance for asset management
- Asset class objectives and life cycle management strategies
- Asset inventory, condition methodology, condition findings, risks, opportunities and renewal strategies
- Optimized five-year capital plan required to manage assets from 2021-2025

This Asset Management Plan aligns with the *ISO5500X* industry standard, the Institute of Asset Management and the Global Forum on Maintenance and Asset Management. This document is intended to meet the OEB's expectations as set out in the *Handbook for Utility Rate Applications* and the *Filing Requirements for Natural Gas Rate Applications*.

2.2 Company Purpose, Vision, Values and Strategic Priorities

Asset management supports Enbridge's Purpose, Vision and Values (**Figure 2.2-1**) by improving the company's ability to operate safely and reliably, ultimately maintaining the satisfaction of our customers and other stakeholders. Asset management provides the necessary structure to make informed asset decisions and execute the resultant actions. In this regard, it is imperative that the framework of asset management at Enbridge is aligned with enterprise strategic priorities.

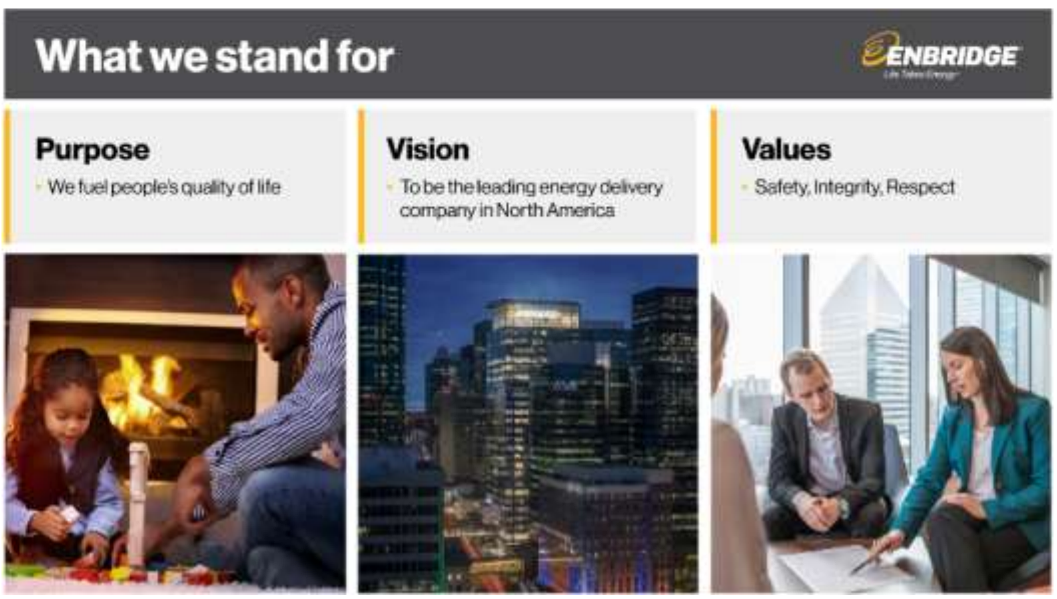

Figure 2.2-1: Enbridge Purpose, Vision and Values

Purpose: *We fuel people's quality of life.*

Enbridge delivers energy where and when it is needed and does so reliably, efficiently and always with the safety of employees, the public and the environment in mind. Asset management at EGI ensures these elements of quality are embedded within EGI's decision-making framework.

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Vision: *To be the leading energy delivery company in North America.*

Enbridge demonstrates leadership in safety, environmental stewardship, customer service, its people, community investment and shareholder value. Asset management ensures asset value is realized by making optimal, transparent and defendable decisions that ultimately provide value to customers and shareholders and exemplify leadership among North American energy delivery companies.

Values: *Safety, Integrity, Respect*

Enbridge continues to build on its foundation of operating excellence by adhering to a strong set of core values–*Safety, Integrity and Respect*–in support of its communities, the environment and its people. Asset management helps maintain the integrity of assets to ensure Enbridge operates safely and reliably, respecting customers and stakeholders.

2.2.1 Strategic Priorities

Enbridge's 2020 Enterprise Strategic Priorities (**Figure 2.2-2**) are defined to enable the organization to achieve its vision to be the leading energy delivery company in North America. Asset management actions and decisions align with these strategic priorities, contribute to Enbridge's success and support the company purpose of fueling people's quality of life, while maintaining the foundation of the business and positioning the company for future growth.

Figure 2.2-2: Enbridge Enterprise Strategic Priorities

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2.3 Organization and Structure

Enbridge carries out its activities through three core business units: Liquids Pipelines, Gas Transmission and Midstream and Gas Distribution and Storage (GDS) (**Figure 2.3-1**). The GDS business includes EGI and other affiliate companies.

In addition, Enbridge's Central Functions teams (Finance, Legal, Human Resources, Technology and Information Services, Supply Chain Management, Public Affairs and Communications, Real Estate and Workplace Solutions, Safety and Reliability and Projects) enable business units to achieve their strategic goals.

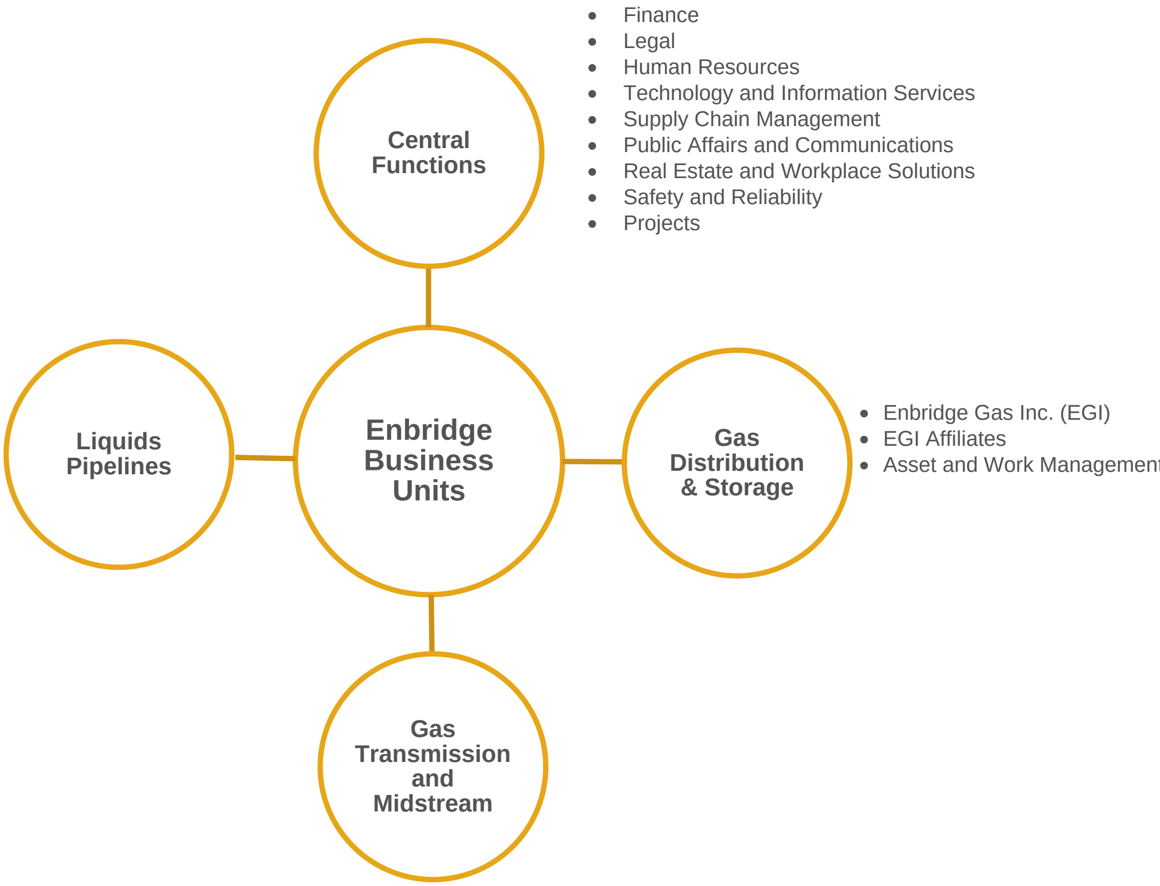

Figure 2.3-1: Enbridge Business Units

EGI within Ontario is regulated by the Ontario Energy Board (OEB). This Asset Management Plan outlines the management of EGI's regulated assets in Ontario.[4]

[4] *Community expansion investments are not included in this Asset Management Plan.*

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2.3.1 Enbridge Gas Inc.

EGI serves over 3.7 million residential, commercial and industrial customers in Ontario delivering heating to more than 75% of Ontario's homes. EGI's franchise area is divided into seven operating regions as shown in **Figure 2.3-2**:

- Northern Region covers the legacy UGL Eastern, Northwest and Northeast districts.
- Eastern Region covers Ottawa and the surrounding region.
- Southwest Region covers the Windsor/Chatham and the Sarnia/London areas.
- Southeast Region covers the Waterloo/Brantford and the Halton/Hamilton areas.
- GTA West and Niagara Region covers the western Greater Toronto Area and Niagara.
- GTA East Region covers the eastern Greater Toronto Area.
- Toronto Region covers the city of Toronto.

EGI has storage and transmission assets that serve to receive, store and transport natural gas for markets in Ontario, Quebec, the Maritimes and major U.S. natural gas consuming areas. EGI's Dawn Hub in southwestern Ontario is connected to most of North America's major natural gas basins, including abundant and affordable gas supplies in the Western Canadian Sedimentary Basin and the Utica and Marcellus producing regions. It is similarly connected to the major demand markets. Like spokes of a wheel, more than half a dozen major pipelines connect at Dawn.

EGI transports gas from the Dawn Hub to the GTA through its West, Central and East transmission operations areas.

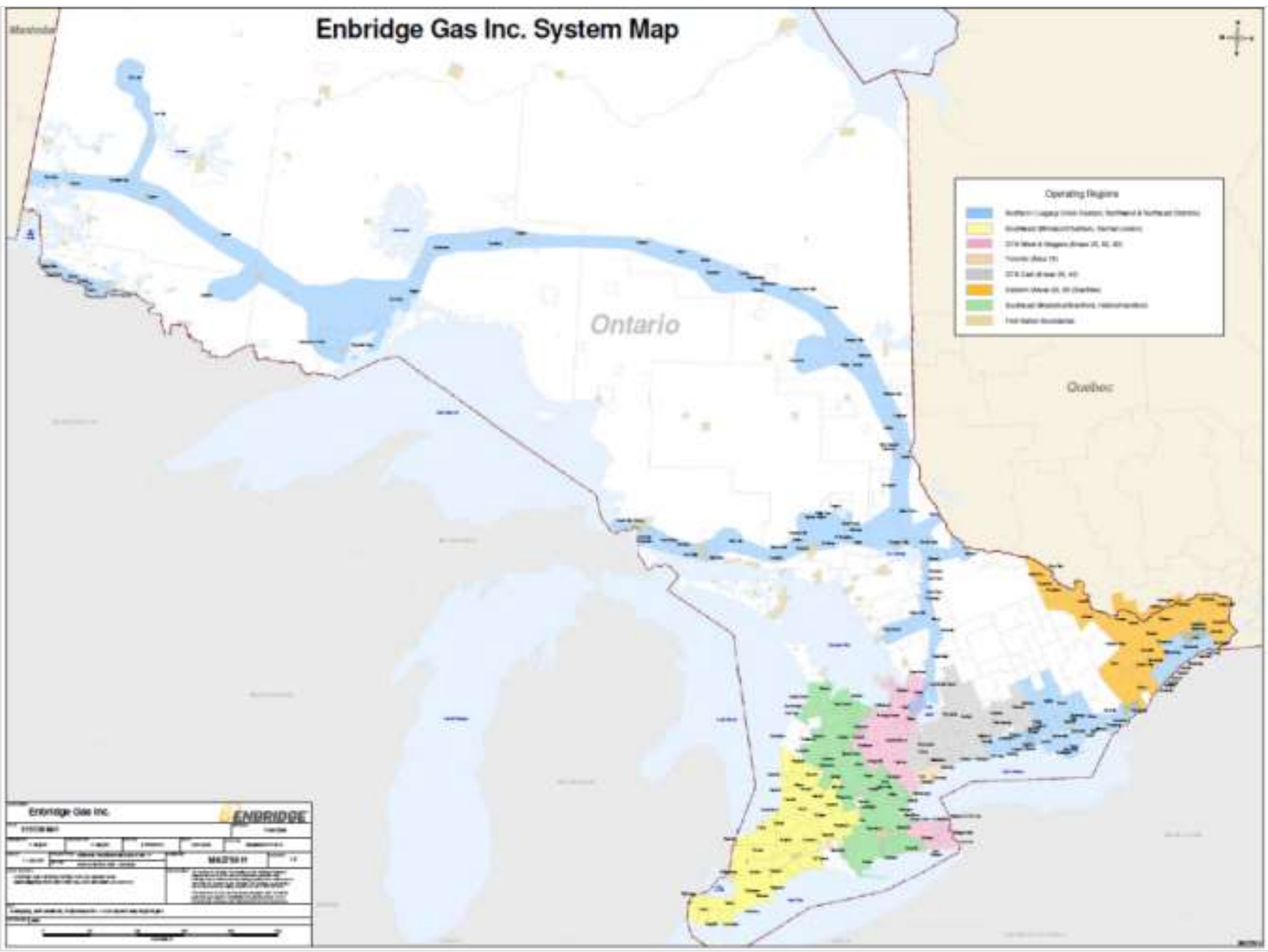

Figure 2.3-2: EGI Operating Regions

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2.4 Stakeholder Commitment

EGI is committed to its customers, regulatory bodies and other stakeholders to identify, build and maintain mutually beneficial relationships. EGI engages its stakeholders to maintain awareness and drive involvement at the inception of new projects and throughout regular operations. Understanding stakeholders and their concerns is critical to making good business decisions and mitigating risk. There is a direct link between EGI's ability to listen and respond to public concerns, the ability to manage costs and regulatory approval timelines. Asset management at EGI and this Asset Management Plan are a direct demonstration of the company's commitment to its stakeholders to ensure asset value is realized and optimal decisions are made based on risk and opportunity.

2.4.1 Customer Engagement Results

As per the Rate Handbook released by the OEB on October 13, 2016, utilities are expected to develop an understanding of their customers' interests and preferences and to incorporate these findings into their Utility System Plan (USP). EGI's Asset Management Plan is a component of the USP. The Rate Handbook directs that *"Utilities are expected to demonstrate value for money by delivering genuine benefits to customers and providing services in a manner which is responsive to customer preferences. Customer engagement is expected to inform the development of utility plans and utilities are expected to demonstrate in their proposals how customer expectations have been integrated into their plans, including the trade-offs between outcomes and costs."*

To this end, EGI commissioned a third-party global market and research specialist, Ipsos Public Affairs, to conduct a customer engagement survey. This survey provides insight into the satisfaction, needs and preferences of EGI's customers on future initiatives and investment plans. This research is intended to complement EGI's regular customer satisfaction surveys (which are used more frequently to monitor the perception and trust of customers as it relates to the interactions and dealings with the company) and more specifically focuses on:

- Overall customer satisfaction
- Satisfaction with safety, reliability, customer service and value
- Willingness to pay for maintaining or improving service
- Pacing of spend

The survey collects feedback from both residential and business (contract and non-contract) customers. The results are important inputs to EGI's investment planning activities and exemplify EGI's commitment to its customers. Key themes formed by the responses are:

- Strong majorities of both residential (88%) and business customers (77% non-contract and 79% contract) express satisfaction with the natural gas services they receive from EGI. Virtually all customers are satisfied with the safety and reliability of the natural gas service they receive to their home or business, while a majority of residential and business customers are satisfied with the value for money and customer service they receive.

- When asked if EGI should invest in improving or maintaining levels of natural gas safety, reliability and customer service, the highest proportion of residential customers would prefer that the organization focus on maintaining current levels.

- Safety, reliability and affordability are rated as being highly important customer outcomes by business and residential customers. Helping customers become more informed and community-mindedness or social responsibility are rated as the least important. When asked to rank the importance of various aspects of their natural gas service, providing stable and predictable pricing is ranked within the top four categories among all customers, while minimizing the impact on the environment is ranked third among residential customers.

- **Replacing Pipelines and Equipment (in general)**: Over half of residential customers (58%) prefer to spread costs evenly over time, even if that means higher rates now. Preferences among business customers are similar to residential customers. Contract business customers are slightly more likely to prefer to spread costs evenly over time.

- **Replacing Older Pipelines**: Half of residential customers (52%) prefer to replace older pipelines all at one time, knowing that for one project example this would translate into an increase of $3 in their natural gas bill per year. Preferences for non-contract business customers are evenly split. Contract customers are more likely to prefer to replace pipelines in phases.

- **Bare and Unprotected Pipes**: Among Union rate zone customers, slightly more than half of residential customers (58%), half of contract business customers (49%) and less than half of non-contract business customers (41%) would prefer that the replacement of bare and unprotected pipes be prioritized, which would increase customer bills. Smaller percentages prefer these pipes remain in place until they would normally be replaced.

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- **Maintenance Operations**: The vast majority of residential (75%), non-contract business (68%) and contract business (69%) customers would prefer that investments in renovating older buildings and building new ones be spread evenly over a longer period of 10 years as opposed to delaying these investments until they can no longer be avoided and funded more quickly, which could cost more in the long run.
- **Fleet Upgrade and Maintenance**: Similarly, a majority of residential (76%), non-contract business (69%) and contract business customers (66%) would prefer that investments for improving fleet vehicles, equipment and tools be spread out evenly over a longer period of 10 years, compared to delaying such investments until they can no longer be avoided and have to be funded more quickly, which could cost more in the long run.

These results demonstrate that customers are aligned with EGI's commitment to the safe, reliable, cost-effective and environmentally responsible provision of natural gas. It also informs and reinforces EGI's asset management decision-making framework. EGI's values and guiding policy statements, outlined in **Section 3.1.2**, align with the preferences of customers in the following ways:

- The core asset management goals are employee and public safety, compliance, financial performance, value-based decision-making, environmental sustainability and value to stakeholders.
- EGI is committed to prudent value-based decision-making for all asset-related investments on a holistic evaluation of risk, cost and performance.
- EGI is committed to understanding and delivering value to its customers.

3. Asset Management Strategic Framework

This Asset Management Plan incorporates the Enbridge Management System Framework, EGI's Integrated Management System (IMS) requirements and demonstrates alignment with the *ISO 5500X* standard and the Institute of Asset Management (IAM) Conceptual Asset Management Model (see **Figure 3.0-1** and **Figure 3.1-1**).

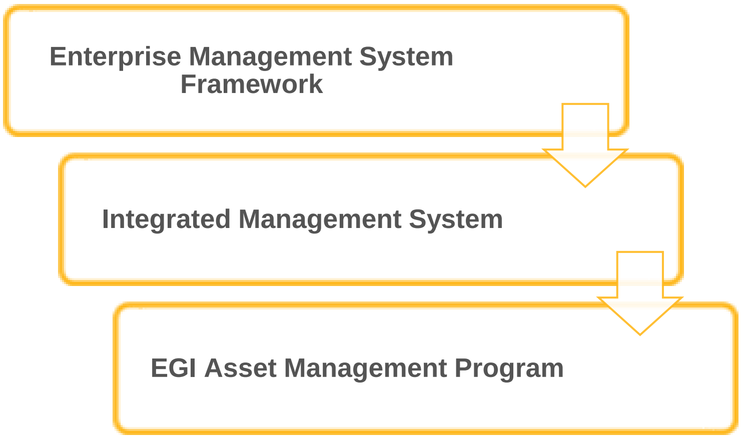

Figure 3.0-1: Alignment of Standards and Requirements

The IMS describes how EGI manages its business to be safe and reliable. Specifically, the IMS outlines high-level management expectations common across the organization and considers over 300 management system requirements from a number of regulatory, corporate and business unit sources, as well as industry standards. The Asset Management Program, one of eight management programs that comprises the IMS, provides more detail on how the program meets its regulatory and corporate obligations related to safety and operational reliability and aligns with the Enterprise Asset Management program.

The IMS is predicated on the underlying principle of striving for continual improvement through the implementation of the Plan-Do-Check-Act (PDCA) quality cycle. As a model for continual improvement, EGI applies the PDCA cycle (**Figure 3.0-2**) to macro- and micro-level activities of the organization. The cycle outlines the activities required to ensure that changes are executed effectively and that continual improvement opportunities are identified.

Plan-Do-Check-Act principles are:

- **Plan**: Establish objectives and processes necessary to deliver results in accordance with expected outcomes and performance targets.
- **Do**: Implement the plan and execute the process.
- **Check**: Monitor the actual results using assessments, internal reviews and audits to compare against the expected outcomes and to ascertain any differences.
- **Act**: Apply corrective and preventive actions on significant differences between actual and planned results. Analyze differences between actual and expected outcomes to determine root causes and how to improve the process.

Figure 3.0-2: Plan-Do-Check-Act Cycle

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3.1 Asset Management Framework

The Institute of Asset Management (IAM) Conceptual Asset Management Model (**Figure 3.1-1**) has been used to build and implement an asset management framework at EGI to balance risk, cost and performance through the entire asset life cycle. By adopting the IAM model, EGI ensures alignment with the *ISO 5500X* standard and demonstrates connections between the subjects of asset management and the elements of the IMS. This model also provides a visual representation of how the asset management discipline connects the various elements and functions across the organization. It further defines asset management planning as the detailed activities, resources and responsibilities for the achievement of asset management goals. This guidance has been used to develop the content and strategy of this Asset Management Plan.

Figure 3.1-1: IAM Conceptual Asset Management Model

Asset Management - An Anatomy Version 3 interprets the *ISO 5500X* standard and provides a practical way to implement its requirements by breaking them down into 39 subjects grouped into six subject groups in alignment with the six major asset management components:

Organization and People: developing and maintaining an adequate supply of competent and motivated people, in key asset management roles across all levels, to support the organization in delivering asset management objectives.

Asset Information: having the right systems, processes and data to support asset management and is foundational to all other asset management capabilities.

Life Cycle Delivery: clear ownership, accountabilities, policies and processes to manage all physical assets throughout their entire life cycle.

Risk and Review: results in the prudent allocation of resources to realize opportunities and manage asset risk.

Asset Management Decision-Making: the organization's approach to making decisions on design, maintenance, operation and disposition in a structured, defendable and repeatable process. This framework allows for the balancing of risk, cost and performance in making asset investment decisions over the whole life cycle of the asset.

Strategy and Planning: the governance framework used to align Asset Management Plans and decision-making within the enterprise's overall strategic objectives at the lowest total cost of ownership.

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3.1.1 Enbridge Enterprise Strategic Priorities

The Enbridge Enterprise Strategic Priorities (**Section 2.2.1**) are defined to enable the enterprise to achieve its vision to be the leading energy delivery company in North America. Asset management actions and decisions align with these strategic priorities and contribute to Enbridge's success. They support Enbridge's purpose of fueling people's quality of life, while maintaining the foundation of the business, positioning the organization for the future and supporting EGI's ambition to be the utility and sustainable energy provider of choice.

The Asset Management Policy translates Enbridge's strategic priorities into a series of policy statements that guide all aspects of the asset management system.

3.1.2 Asset Management Policy

Vision and Mandate

Enbridge exists to fuel people's quality of life with a long-term vision to be the leading energy delivery company in North America. Enbridge Gas Inc. (EGI) is committed to the safe, reliable, cost-effective and environmentally responsible provision of natural gas to its customers. At the core of this commitment is the effective stewardship of EGI's assets through governance, policy and practices. EGI will apply leading asset management practices to effectively manage the life cycle of assets. Optimal value will be delivered to customers and stakeholders through a sustainable investment plan that balances risk, cost and performance.

Scope

The Asset Management Program considers all EGI assets, inclusive of commodity-carrying assets directly related to the task of transporting natural gas from the source to the end-use customer, as well as assets that support business operations. The asset classes are: Distribution Pipe, Distribution Stations, Utilization, Growth, Compression Stations, Liquified Natural Gas, Transmission Pipe and Underground Storage, Fleet and Equipment, Real Estate and Workplace Services, and Technology and Information Services. At this time, the Asset Management Program does not consider EGI's affiliates. The Asset Management Program is a component of EGI's Integrated Management System, which provides a systematic approach to managing safety and reliability across the organization.

Asset Management Program

Core asset management goals are employee and public safety, compliance, financial performance, value-based decision-making, environmental sustainability and value to stakeholders. EGI employees must consider these goals when evaluating costs, risks and performance related to asset investment decisions. These goals should also be considered during the installation, operation, maintenance and disposal of assets. Decisions are made through documented and transparent evaluation processes.

EGI will leverage an Asset Management Program based on the industry standard, *ISO5500X*, to demonstrate a systematic and coordinated approach to asset management activities. Consistent practices, processes and tools will be used to optimally and sustainably manage assets; this will be achieved by balancing risk, cost and performance throughout the assets' life cycle while providing value to customers and stakeholders.

Policy Statements

1. EGI will continuously improve and align its asset management approach across all asset classes within EGI by driving innovation in the development of people, tools, processes and solutions.
2. EGI is committed to prudent value-based decision-making for all asset-related investments on a holistic evaluation of risk, cost and performance.
3. EGI is committed to continual comprehensive condition assessment and risk review. EGI acknowledges that the understanding of the asset's life cycle is critical for decision-making and the safe and reliable delivery of natural gas.
4. EGI acknowledges that asset information is critical to transparent knowledge-based decision-making. EGI shall work to ensure that its processes, systems and controls collectively strive to deliver verifiable, traceable, complete, timely, accurate and accessible asset information.
5. EGI is committed to sustainable/lower carbon initiatives and new energy solutions, as well as the incorporation of these strategies within asset management planning and investment decisions.
6. EGI is committed to meeting or exceeding compliance with all applicable laws and regulations, industry codes, standards and internal policies and will strive to align with industry standards and the Enterprise Asset Management vision.
7. EGI is committed to understanding and delivering value to its customers and stakeholders.
8. EGI shall use this Policy and EGI's Asset Management Program to guide asset investments and their endorsement by Senior Leadership over the life cycle of each asset class.

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3.2 EGI Integration and Continual Improvement

On October 25, 2019, EGI filed an Asset Management Plan (AMP) Addendum to the 2019-2028 AMPs previously filed by EGD and UGL, to provide an update to budget year 2020 for each of the two existing plans. This 2021-2025 AMP document reflects the integrated utility's Asset Management Plan for the next five years, with assets for the rate zones (the EGD and Union North and South rate zones) being maintained separately for capital planning purposes through to the end of 2025[5].

EGI continues to evolve its asset management practices to produce a comprehensive Asset Management Plan. As a result, the following changes were implemented:

- **Alignment with Enbridge Inc.'s 2020 Enterprise Strategic Priorities**

  Enbridge Inc. published a revised Strategic Plan in 2020. The alignment of EGI's Asset Management Policy, Asset Management Strategies and dimensions of risk have been reviewed to confirm alignment and are found in **Section 4**.

- **Implementation of a new asset investment planning module**

  Copperleaf C55 is an asset investment planning tool that centralizes asset investment decision-making through a value and risk framework that balances risk, cost and performance across an asset's life cycle. C55 was implemented at EGI in January 2020, as part of Enbridge Inc.'s Enterprise Asset Management program. Use of a single tool will provide consistency across the integrated company and visibility to investments that are part of the plan as well as those that are required to address emergent concerns, changes to municipal or customer needs and changes to cost estimates. C55 will help EGI evaluate options, efficiently manage its dynamic portfolio of asset investments, provide the governance and oversight to achieve the best return for its investments and satisfy regulatory commitments.

- **Organizational structure changes to align roles and responsibilities within the integrated utility**

  The amalgamation of the legacy utilities included alignment of roles across both organizations. A new asset management reporting structure was set up with asset manager roles aligned to new processes, asset class hierarchies, governance roles and functional department support. A matrix approach to asset management enables the coordinated activity of defining an optimized and approved portfolio of work. This streamlines inputs from a diverse group of business stakeholders, while growing asset management practices across EGI. Specific roles and accountabilities in the matrix approach include:

  - **Asset Managers**: accountable to manage asset performance, support maintenance and operations and lead an asset knowledge community within their respective asset classes in identifying risks and opportunities.
  - **Asset Management Governance**: accountable for overall governance of systems and methodology, risk management framework and analysis, portfolio optimization and the Asset Management Plan.
  - **Knowledge Communities consisting of Subject Matter Advisors (SMAs)**: accountable for supporting asset managers on hazard or opportunity identification, investment assessments, planning and project execution.

- **Consolidation of UGL asset data**

  The systems of record for asset data in the Union rate zones include Banner for meter data, Service Suite for work and condition data, RiskMaster for damages, SAP-PM for station work and asset data, GIS for pipe data and CORR for corrosion data. An initiative was completed in Q3 2019 to document and create a copy of this information in a centralized data repository through a series of extract, transform and load (ETL) interfaces. The documentation and consolidation of UGL data enabled EGI to more efficiently analyze inventories for the combined utility and support the development of the consolidated Asset Management Plan.

- **Evolution of asset condition and strategies**

  Section 5, which addresses asset inventory, condition, risk/opportunity and strategy outcomes, has been updated to reflect the current understanding of assets. Specific project and program information is provided in **Section 6** to support each asset class's strategic plans. Key changes are:

  - Review, comparison and integration where feasible of asset strategies, asset classes, asset condition, inventories, programs and processes between the two legacy companies
  - Identification of outstanding items that remain in legacy programs until they can be integrated

[5] *The deferred rebasing period is from 2019-2023. Asset Management will reflect the new regulatory framework once it becomes available.*

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3.3 Integrated Resource Planning (IRP)

Integrated Resource Planning (IRP) impacts have not explicitly been reflected in this asset management plan. As part of its 2021 Dawn Parkway Expansion project and IRP Proposal Application (*EB-2019-0159*) filed November 1, 2019, EGI requested that the OEB make a determination that the policy direction set out in its IRP Proposal is reasonable and appropriate. The IRP Proposal submitted sought to establish "*an IRP framework to guide Enbridge Gas's assessment of IRPAs [IRP alternatives] relative to other facility and non-facility alternatives to serve the forecasted needs of Enbridge Gas customers*"[6]. In its *Procedural Order No. 1* for the 2021 Dawn Parkway Expansion project proceeding the Board determined that, *"…the IRP Proposal, as it relates to future Enbridge projects, will be reviewed separately at a later date to be determined by the OEB."*[7]

Through a combined letter and Notice of Hearing dated April 28, 2020, the OEB subsequently initiated a proceeding to review EGI's IRP Proposal *(EB-2020-0091)*. In its *Decision on Issues List* and *Procedural Order No. 2* dated July 15, 2020, the OEB defined the scope for the IRP Proposal proceeding including a final Issues List and set out an initial procedural timeline. The OEB's latest procedural timeline, set out in *Procedural Order No. 4* dated August 20, 2020, includes deadlines for EGI, OEB Staff and approved intervenors to submit additional evidence and responding evidence from October 15, 2020 to December 11, 2020.

Consistent with the OEB's intentions stated in its *Decision on Issues List* and *Procedural Order No. 2* to establish an IRP Framework for EGI[8], and considering EGI's intention to file an illustrative IRP process plan that will include "*a proposal for incorporating IRP into Enbridge Gas's system planning processes (e.g. the Asset Management Plan).*"[9], EGI expects that the IRP Proposal proceeding will ultimately establish an IRP Framework that will enable consideration of IRPAs as part of the utility asset management planning process going forward.

3.4 Structure and Scope of EGI's Asset Management Plan

Figure 3.4-1 is an illustration of EGI's Asset Management Plan structure.

Figure 3.4-1: EGI's Asset Management Plan Structure

Introduction (Section 2) and **Asset Management Strategic Framework (Section 3):** This plan starts with an introduction to EGI. It also highlights EGI's stakeholder commitment, the asset management framework and policy, updates and improvements from previous Asset Management Plans, and the structure of the document.

Strategy, Planning and Process (Section 4): This section details the alignment of asset management at EGI with the enterprise strategic priorities and includes EGI's asset management strategies and the asset management core process.

6 *EB-2019-0159, Exhibit A, Tab 13, p. 1.*
7 *EB-2019-0159, OEB Procedural Order No. 1, pp. 1-2.*
8 *EB-2020-0091, OEB Decision on Issues List and Procedural Order No. 2, p. 2.*
9 *EB-2020-0091, Enbridge Gas Letter, Aug. 27, 2020, p. 1.*

Customers and Assets (Section 5): This section details the following for each asset class:

- Asset class objectives
- EGI's customers and the customer growth projections
- Asset inventory
- Asset condition
- Risks and opportunities
- Strategy outcomes
- Capital investments to meet life cycle strategies

Summary of Capital Expenditure (Section 6): This section summarizes the five-year capital investment plan for EGI by rate zone, outlines the optimization process and highlights key assumptions used for **Sections 5** and **6**. Note that projects where solution scopes are still under development are not currently included in EGI's five-year portfolio of spend.

Appendices (Section 7): The appendices present supporting information for the Asset Management Plan.

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4. Strategy, Planning and Process

EGI's Asset Management framework is aligned to Enbridge's Enterprise Strategic Priorities, the EGI Asset Management Policy and Asset Management Strategies (**Section 4.1**). This alignment provides a foundation that supports the Asset Management Core Process (**Section 4.2**).

Figure 4.0-1: Asset Management Alignment

The Enbridge Enterprise Strategic Priorities (**Section 2.2.1**) sets the foundation for all company-wide operations and initiatives. The Asset Management Policy (**Section 3.1.2**) translates the Enterprise Strategic Priorities into the application of asset management at EGI and outlines the high-level goals and principles used to manage assets. Asset Management Strategies (**Section 4.1**) support the policy and outlines the methods employed for asset management success. Lastly, the Asset Management Core Process (**Section 4.2**) outlines how the identified strategies will be executed.

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4.1 Asset Management Strategies

The EGI Asset Management Program's day-to-day activities are driven by key asset management strategies aligned to the six framework components of the IAM model and operationalized through the Asset Management Core Process (**Section 4.2**):

Figure 4.1-1: Asset Management Strategies

Organization and People Strategies

- Align roles and organizational structure to support asset management.
- Define organizational roles and structure to deliver on effective decision-making in asset management.
- Clarify competencies and build capacity in the organization to deliver on asset management goals.
- Ensure adequate capacity to deliver on asset management objectives.
- Establish a leadership culture/framework to embed asset management awareness and principles throughout the organization.

Asset Information Strategies

- Produce and evaluate asset information and condition information.
- Establish a governance framework to ensure data is captured, managed and used effectively in decision-making.

Life Cycle Delivery Strategies

- Implement life cycle management for assets.
- Ensure asset decision-making is compliant with applicable standards and legislation.
- Build life cycle strategies for assets that consider the design and operational context throughout the asset life cycle.
- Use life cycle strategies for assets to drive consistent and holistic evaluation of investment opportunities.

Risk and Review Strategies

- Establish a framework to identify, manage and treat risk.
- Use processes for the identification, assessment, analysis and treatment of risks and opportunities.
- Monitor asset performance and health to ensure a balance of risk, cost and performance.

Asset Management Decision-making Strategies

- Optimize portfolio based on asset management principles.
- Improve decision-making through transparency, clear accountabilities, stakeholder engagement and use of a common asset management tool.
- Extend asset management decision-making to further include operations and maintenance activities to ensure that optimal asset value is attained over each asset's life.
- Improve decision-making through an understanding of the asset context and timing considerations for outages.

Strategy & Planning Strategies

- Create alignment in the organization by establishing an asset management policy, strategies and objectives that link to company strategic priorities.
- Develop and use processes for the repeatable practice of asset management.
- Forecast a long-term Asset Investment Plan that supports strategic priorities.

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4.1.1 Organization and People

EGI aims to develop and maintain an adequate supply of competent and motivated people, in key asset management roles across all levels, to support the organization in delivering asset management objectives. The strategies to achieve this are:

- Align roles and organizational structure to support asset management.
- Define roles and structure for the organization to deliver on effective decision-making and asset management.
- Clarify competencies and build capacity in the organization to deliver on asset management goals.
- Ensure adequate capacity to deliver on asset management objectives.
- Establish a leadership/culture framework to embed asset management awareness and principles throughout the organization.

Asset classes at EGI (**Figure 4.1-2**) are used to categorize and manage investment decisions. Each asset class has its own asset manager, who is responsible for understanding the operational risks and opportunities of their respective asset class and for managing the portfolio of work to ensure risk is managed to the lowest practicable level and optimum value is realized.

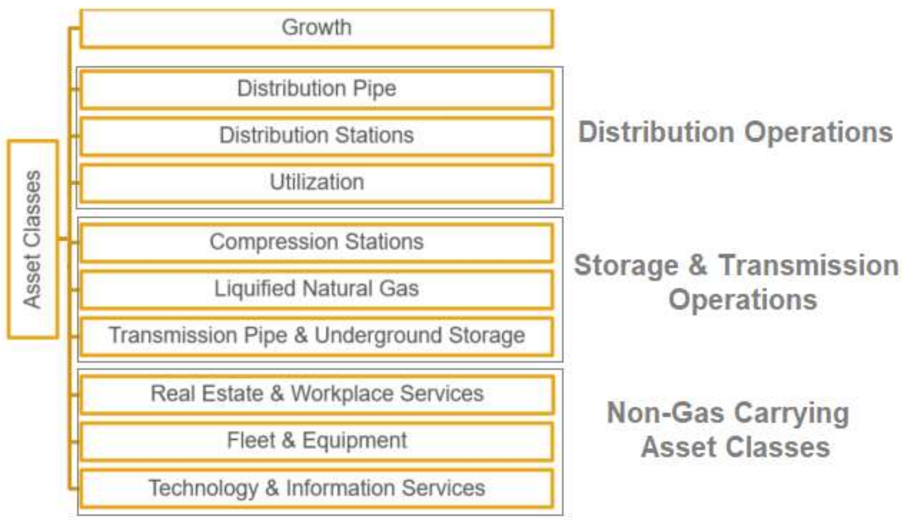

Figure 4.1-2: EGI Asset Classes

A matrix approach to asset management (**Figure 4.1-3**) enables the coordinated activity of defining an optimized and approved portfolio of work. This streamlines inputs from a diverse group of business stakeholders, while growing asset management practices across EGI.

Asset management is embedded throughout all levels of the organization. Overall guidance is established through the Asset Management Steering Committee, the Integrated Management System and the Safety and Reliability Governance Team. Key functions in this matrix approach work together to achieve an optimized portfolio:

Asset Management Governance establishes and governs the following:

- Asset Management Policy
- Leadership culture to embed Asset Management principles (through organizational change management and training)
- Asset management systems and methodology
- Risk management framework
- Risk analysis and review
- Asset management processes and tools
- Portfolio optimization
- Preparation and approval of the Asset Management Plan

Asset Managers perform the following:

- Understanding of asset condition and failure drivers
- Consolidation of emerging and existing risks and opportunities
- Preparation of business cases for risk review
- Proposal of potential solutions to identified risks
- Prioritization of solutions across the asset class
- Development of strategic plans for the asset class
- Stakeholder review

Functional/process departments support asset management by providing:

- Engineering assessments
- Integrity assessments
- Asset analytics
- Records management
- Financial support
- Regulatory support
- Tacit knowledge (including identification of existing and emerging issues)
- Planning and design
- Safety and incident information
- System analysis long range planning
- Project execution

Together, these roles provide the structured support for the Asset Management Core Process described in **Section 4.2** to ensure that capital expenditures are based on transparent and defendable asset-based decisions.

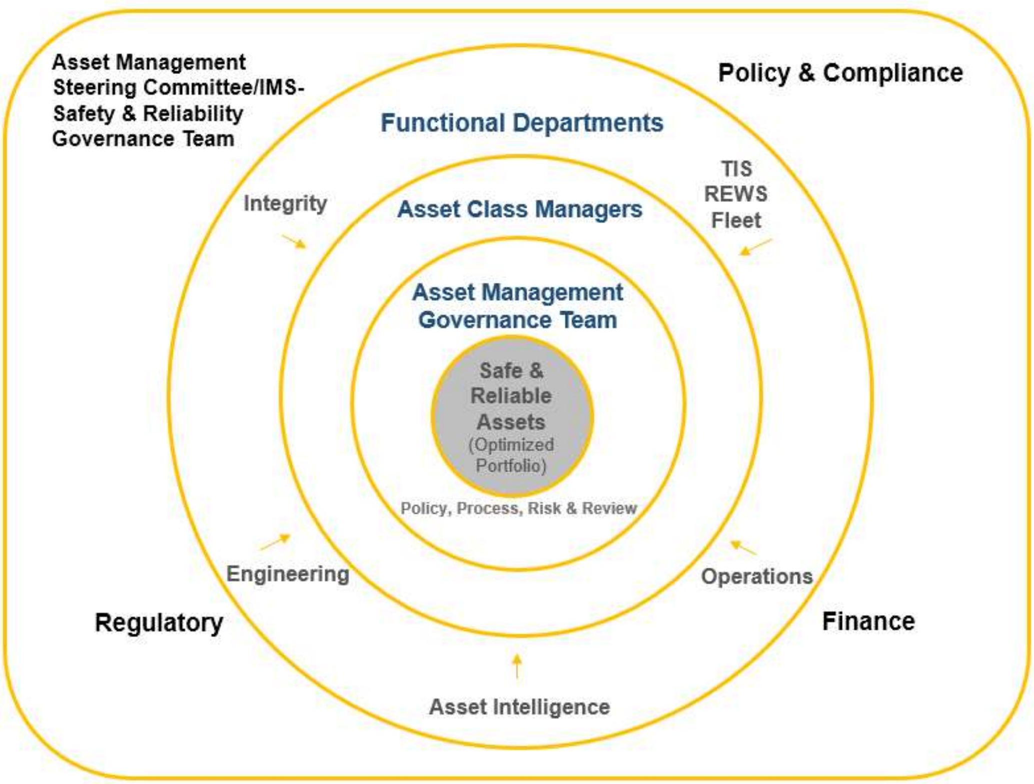

Figure 4.1-3: A Matrix Approach to Asset Management

4.1.2 Asset Information

EGI aims to have the right systems, processes and data to support asset management–this is foundational to all other asset management capabilities. The strategies to achieve this are:

- Produce and evaluate asset information and condition information.
- Establish a governance framework to ensure data is captured, managed and used effectively in decision-making.

Asset data provides the foundation for asset investment planning, as seen in **Figure 4.1-4**. Asset analytics supports people, process and technology advancements to enable defendable asset decisions. Asset analytics provides asset information that informs and supports asset health reviews, engineering reliability assessments, risk and opportunity assessments and asset replacement strategies. It also outlines the processes, governance and systems required to ensure decisions are defendable and repeatable through the use of data that is fit for purpose.

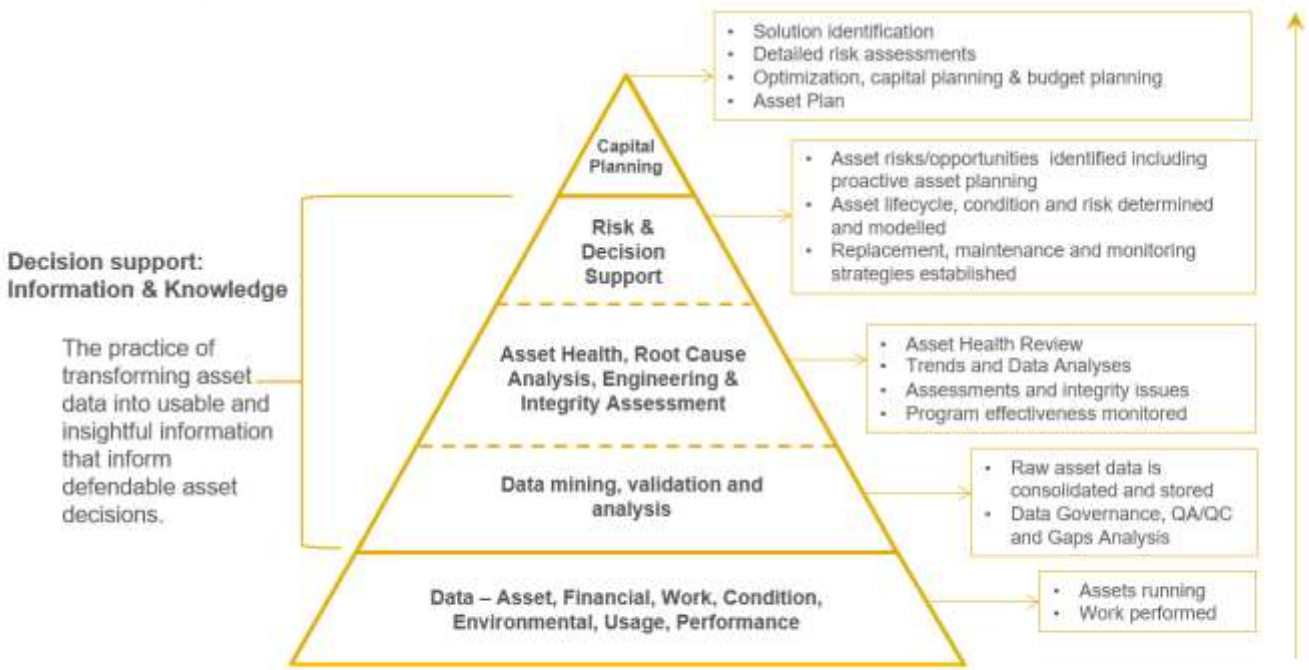

Figure 4.1-4: Asset Information and Support to Asset Investment Planning

Asset data enables the evaluation of existing assets, determines patterns and identifies meaningful information to inform life cycle management strategies. A number of reports and tools are used to understand the condition of assets, as outlined in **Section 4.2.6**. With an understanding of asset failure modes and causes, these tools support business operations to predict asset failure and optimize treatment strategies.

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4.1.3 Life Cycle Delivery

EGI aims to have clear ownership, accountabilities, policies and processes to manage all physical assets throughout their entire life cycle. The strategies to achieve this are:

- Implement life cycle management for assets.
- Ensure asset decision-making is compliant with applicable standards, legislation and regulatory decisions.
- Build life cycle strategies for assets that consider the design and operational context throughout the asset life cycle.
- Use life cycle strategies for assets to drive consistent and holistic evaluation of investment opportunities.

Life cycle strategies for assets will drive consistent and holistic evaluation of needs and opportunities. With clear objectives for the use and operation of assets, life cycle costs can be examined to ensure that optimal asset value is attained over the asset's life.

EGI has defined asset life cycle stages that are applied to all asset classes (**Figure 4.1-5**), adapted from the IAM Conceptual Asset Management Model:

- Design/Construct
- Operate
- Maintain
- Renew/Retire

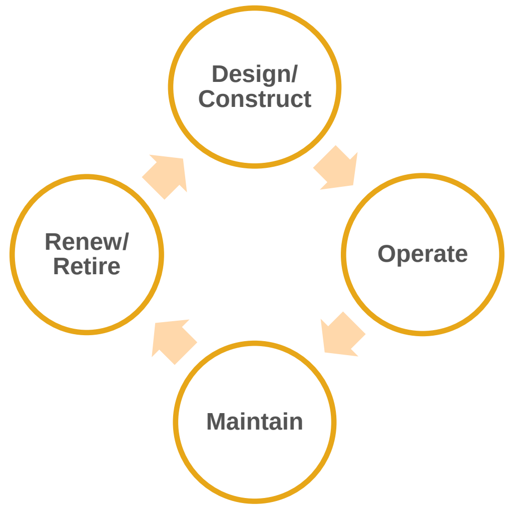

Figure 4.1-5: Asset Life Cycle Stages

Using these stages, strategies are developed for each asset class to support asset investment decisions. **Table 4.1-1** describes the typical activities for each of the life cycle stages.

Table 4.1-1: Life Cycle Management for Assets

Life Cycle Stage	Activities
Design/Construct	• Design new assets to: o Ensure the safe and reliable delivery of natural gas. o Ensure worker and public safety. o Ensure code compliance. o Meet current and future demand requirements. o Reduce risk to the lowest practicable level. o Ensure critical components and systems have multiple layers of failure protection. o Ensure components and systems can be made safe in a reasonable period. o Minimize environmental impact. o Minimize future maintenance needs. o Suit business purpose and ensure safe business function. • Procure materials to meet or exceed applicable codes, standards and policies. • Construct/install assets to meet or exceed codes, standards, designs and procedures for safe and reliable operations. • Create asset records to meet or exceed standards, policies and procedures that are traceable, verifiable, complete and correct.
Operate	• Operate the system to: o Ensure the safe and reliable delivery of natural gas. o Ensure worker and public safety. o Meet or exceed compliance standards and procedures. o Meet current demand. o Minimize end user disruption. o Use assets in the most cost-effective manner. o Extend asset life. • Suitably commission assets for safe, efficient and reliable use by employees and contractors. • Provide business and employees with support and service for optimal use of company assets and business solutions. • Monitor the performance and use of assets to inform future life cycle decisions.

Life Cycle Stage	Activities
Maintain	• Maintain integrity of gas-carrying assets to minimize loss of containment, extend asset life and ensure compliance with codes, standards and procedures. • Maintain gas-carrying assets and safety controls to avoid over-pressure or delivery outages. • Maintain asset information to meet or exceed standards set out by EGI. • Determine probability and consequence of failure to inform maintenance and repair programs. • Maintain competency levels to ensure work is performed by qualified and competent workers. • Continue to improve methods to maintain and extend life of assets, ensuring a balance between risk, cost and performance.
Renew/Retire	• Determine probability and consequence of failure to inform renewal decisions. • Develop proactive renewal programs for assets that are nearing end-of-life (informed by data and tacit knowledge and tracked in the Integrated Management System). • Renew or replace assets to meet the changing needs of the business, support the health and safety of employees, meet or exceed regulatory and compliance requirements, increase efficiencies and reduce overall GHG emissions. • Renew or replace assets to meet the changing needs of the business, increase performance, realize efficiencies and address obsolescence. • Retire assets using a process that meets or exceeds codes and standards.

A number of inputs inform decision-making during an asset's life, as seen in **Figure 4.1-6.** Based on condition and risk, the plans for each asset class will align with their respective life cycle strategies (detailed in **Section 5**).

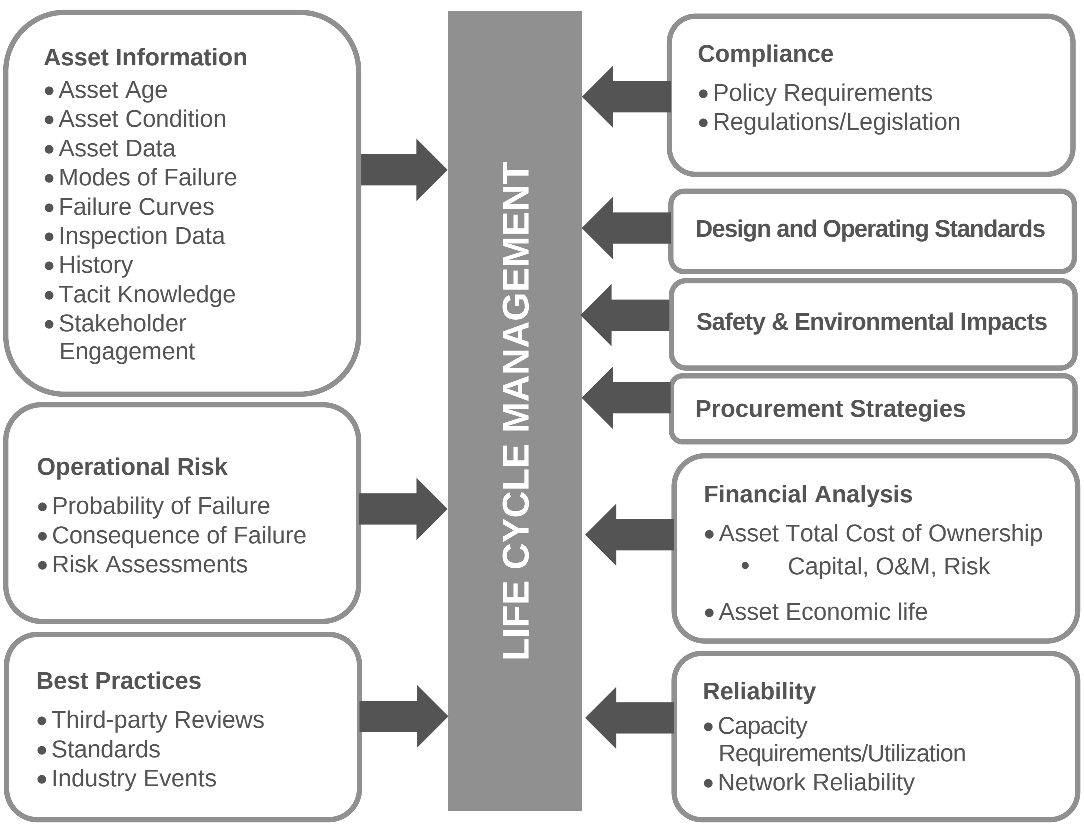

Figure 4.1-6: Life Cycle Management Inputs

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4.1.4 Risk and Review

EGI aims to prudently allocate resources to realize opportunities and manage asset risk. The strategies to achieve this are:

- Establish a framework to identify, manage and treat risk.
- Use processes for the identification, assessment, analysis and treatment of risks and opportunities.
- Monitor asset performance and health to ensure a balance of risk, cost and performance.

For an organization to optimize the use of its limited resources, it must have a mechanism to determine the relative value of each investment. Several elements can contribute to the overall value of an investment, such as:

- The type and severity of the risks treated by an investment
- Financial impacts such as cost savings
- Overall cost of the investment
- Impacts to Key Performance Indicators (KPIs)
- Service measures
- Overall organizational value adds

An investment's net value is then used to determine both its independent merit and its standing among other investments competing for resources in a constrained optimization process. The Copperleaf C55 value framework is the enterprise-developed decision criteria that complements risk assessments, allows for comparison of dissimilar assets and enables portfolio optimization. Using this framework, risks and opportunities (see **Table 4.1-2**) are evaluated consistently across asset classes.

Table 4.1-2: Risk and Opportunity

Term	EGI Description
Risk	A *negative* effect of uncertainty on the organization's objectives expressed as a combination of the likelihood and consequences of a potential event.
Opportunity	A *positive* effect of uncertainty on the organization's objectives expressed as a combination of the likelihood and consequences of a potential event.

Enbridge uses a risk matrix (**Figure 4.1-7**) built around the types of risks that are important to the organization and their associated consequences by severity level:

Figure 4.1-7: Enbridge Risk Matrix

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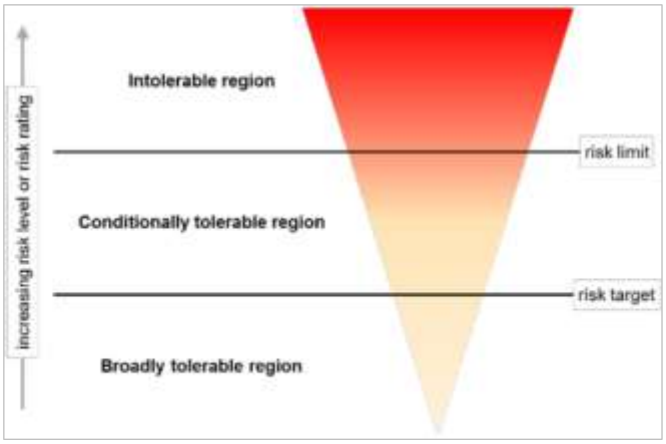
EGI considers the following risk categories:

- **Employee and Contractor Health and Safety**: Level of injury or illness due to incident
- **Public Health and Safety**: Level of injury and number of people impacted
- **Environmental**: Breadth and severity resulting in environmental damage/impact
- **Financial**: Level of financial impact
- **Operational**: Length of time and breadth of impact on utility & transportation customers and diversion of resources
- **Reputational**: Level of media coverage, impact on customers, potential penalties or impact on ability to operate due to compliance issues

Adequately managing risk means reducing risk to conditionally tolerable or broadly tolerable levels, rather than as low as possible, as seen in the Enbridge Risk Tolerability Model (**Figure 4.1-8**).



Source(s): Adapted from IEC/ISO 31010 (2018); HSE R2P2 (2001)

Figure 4.1-8: Enbridge Risk Tolerability Model

When a risk is evaluated to be in the intolerable (red) region, the project required to treat the risk is labelled as mandatory and must be addressed. Other mandatory initiatives are those driven by compliance requirements and third-party relocations (summarized in **Table 4.1-3**).

Table 4.1-3: Investments to Address Risk

Term	EGI Description
Mandatory	An investment that is required to address a risk within its required time window. Mandatory investments can be the result of: • Compliance requirements • Exceeding an established risk tolerance • Third-party relocation driven • Program work with sufficient history and risk to warrant continuation • Projects that meet the economic feasibility tests in *EBO 188* and *EBO 134*
Compliance	Required adherence with applicable laws and regulations, industry codes, standards and internal policies.
Risk/Opportunity Driven	All other investments are optimized based on the value that they bring, including all of the measures noted above.

In the Risk Tolerability Model, EGI's objective is to reduce all known risks in the intolerable (red) region to the conditionally tolerable (yellow) or broadly tolerable (light yellow) regions. Enbridge uses a Risk Bowtie Model (**Figure** 4.1-9) to evaluate risks and focuses on frequency, outcome and impact evaluation.

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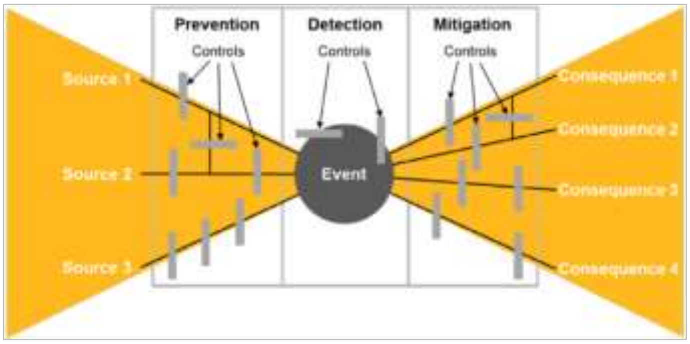

Source: Adapted from IEC/ISO 31010 (2009)

Figure 4.1-9: Risk Bowtie Model

Once a risk is classified and an investment identified to treat the risk, **value measures** are used to quantify an investment's value through the C55 value framework. Value measures are investment attributes that are evaluated objectively to determine how the investment delivers value to Enbridge. These value measures are then placed on an economic scale to assist in optimization. Each of the enterprise's strategic priorities (**Section 2.2.1**) is comprised of one or more value measures. See **Section 4.2.3** for more details on valuing investments.

Table 4.1-4 lists the value measures used to determine the value of each investment.

Table 4.1-4: EGI's Value Measures

Value Measure	Description
Employee and Contractor Safety Risk	Measures the risk of employee and contractor safety incidents that will be mitigated through the completion of an investment.
Public Safety Risk	Measures the risk of public safety incidents treated through the completion of an investment.
IT and Facilities Capacity Risk	Measures the risk that the organization would not be capable of continued service at acceptable levels following a disruptive incident.
Operational Risk	Measures the mitigation of the risk of disruptive incidents preventing Enbridge from operating or serving its customers.
Reputational Risk	Measures the treatment of the risk of incidents that would be perceived poorly by customers, the media and stakeholders through the completion of an investment.
Gas Storage Reliability	Measures the financial benefits of investments that increase the reliability of gas storage assets to prevent supply interruptions.
Environmental Risk and Remediation	Measures the treatment of risk of environmental incidents through the completion of an investment.
Operational Disruption Risk (Gas)	Measures the societal cost of a disruption in the distribution of gas to customers.
Growth Per Year	Measures the expected customer growth per year the system serves.
Avoided GHG Emissions	Measures the monetary value of reducing CO2 greenhouse gas emissions through the completion of an investment.
Avoided Reactive Replacement	The financial savings of replacing an asset proactively before it fails and not having to pay the higher, reactive replacement costs.
Financial Risk	Measures the treatment of potential financial risks, such as financial losses due to damage of equipment/company assets, if the investment is not completed.
Revenue Impact	Measures the impacts to the total amount of gross income generated by Enbridge's primary operations. Revenue represents the total income earned before expenses are deducted.
Budget Savings OPEX	Values the OPEX Budget Savings of the investment.
Budget Savings CAPEX	Budget savings is the net benefit between the anticipated cost increases to the CAPEX budget as well as cost savings to current planned spending. This is not the Investment Cost.
Cost Avoidance OPEX	Any action that avoids having to incur OPEX costs in the future (these costs would be unbudgeted/not planned). Cost avoidance measures are never reflected in financial

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Value Measure	Description
	statements or the annual budget. Avoided OPEX costs are only reflected in instances where a proposed action is not implemented, thus resulting in a cost increase.
Cost Avoidance CAPEX	Any action that avoids having to incur CAPEX costs in the future (these costs would be unbudgeted/not planned). Cost avoidance measures are never reflected in financial statements or the annual budget. Avoided CAPEX costs are only reflected in instances where a proposed action is not implemented, thus resulting in a cost increase.
Energy Efficiency	Measures the financial benefits through annual power savings and reduced CO2 emissions.
Employee Productivity	Measures the impact on working conditions and employee productivity.

4.1.5 Asset Management Decision-making

EGI aims to have a clear framework for asset investment decision-making which balances risk, cost and performance throughout the asset life cycle. The strategies to achieve this are:

- Optimize portfolio based on asset management principles.
- Improve decision-making through transparency, clear accountabilities and stakeholder engagement and use of a common tool.
- Extend asset management decision-making to further include operations and maintenance activities to ensure that optimal asset value is attained over each asset's life.
- Improve decision-making through an understanding of the asset context and timing considerations for outages.

EGI has been implementing and continues to evolve its asset management tools for use by the business; an overview of these tools is provided in **Section 4.2.6.2**. Asset management tools provide the business with the ability to gather and make transparent decisions supported through the assessment of asset condition and risk.

EGI uses Copperleaf C55, an asset investment planning tool that provides a common economic scale, allowing multiple investments to be evaluated against each other to optimize asset performance and manage risk. C55 allows EGI to predict long-term asset needs, optimize its investment portfolio to realize high value, use value-based and risk-informed decision-making and fulfil its regulatory and enterprise requirements for systematic and transparent solutions.

Within the Asset Management Core Process (**Section 4.2**), C55 specifically supports solution planning, portfolio optimization and the necessary monitoring and tracking during program execution. C55 accomplishes this by:

- Allowing the documentation of risk management opportunities and treatment options
- Managing solution planning by determining the value of options through the value framework, based on how they align with the Asset Management Policy and asset management principles
- Performing portfolio optimizations using What-If scenarios to determine an optimal spend profile
- Allowing investment details to be updated throughout the year to optimally manage the investment portfolio

4.1.6 Strategy and Planning

EGI uses a governance framework to align Asset Management Plans and decision-making within the enterprise's overall strategic objectives at the lowest total cost of ownership. The strategies to achieve this are:

- Create alignment in the organization by establishing an asset management policy, strategies and objectives aligned to strategic priorities.
- Forecast a long-term Asset Investment Plan that supports strategic priorities.

The alignment of EGI's Asset Management Program with organizational priorities (**Figure 4.1-10**) and a well-defined asset portfolio enables the development of asset-specific programs and investments. The asset management plan is a coordinated activity combining these components to forecast a long-term (five-year) plan for asset investments at each rate zone. Forecasting long-term asset investment plans allows EGI to identify future needs for asset investments and make proactive decisions.

The capital investment summary for EGI's Asset Management Plan can be found in the Summary of Capital Expenditure (**Section 6**).

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4.1.6.1. Alignment of Enterprise Strategic Priorities and Asset Management Strategies

Figure 4.1-10 illustrates how EGI's Asset Management Policy, strategies and value measures align with Enbridge's enterprise strategic priorities. This alignment is the core of EGI's Asset Management Strategic Framework.

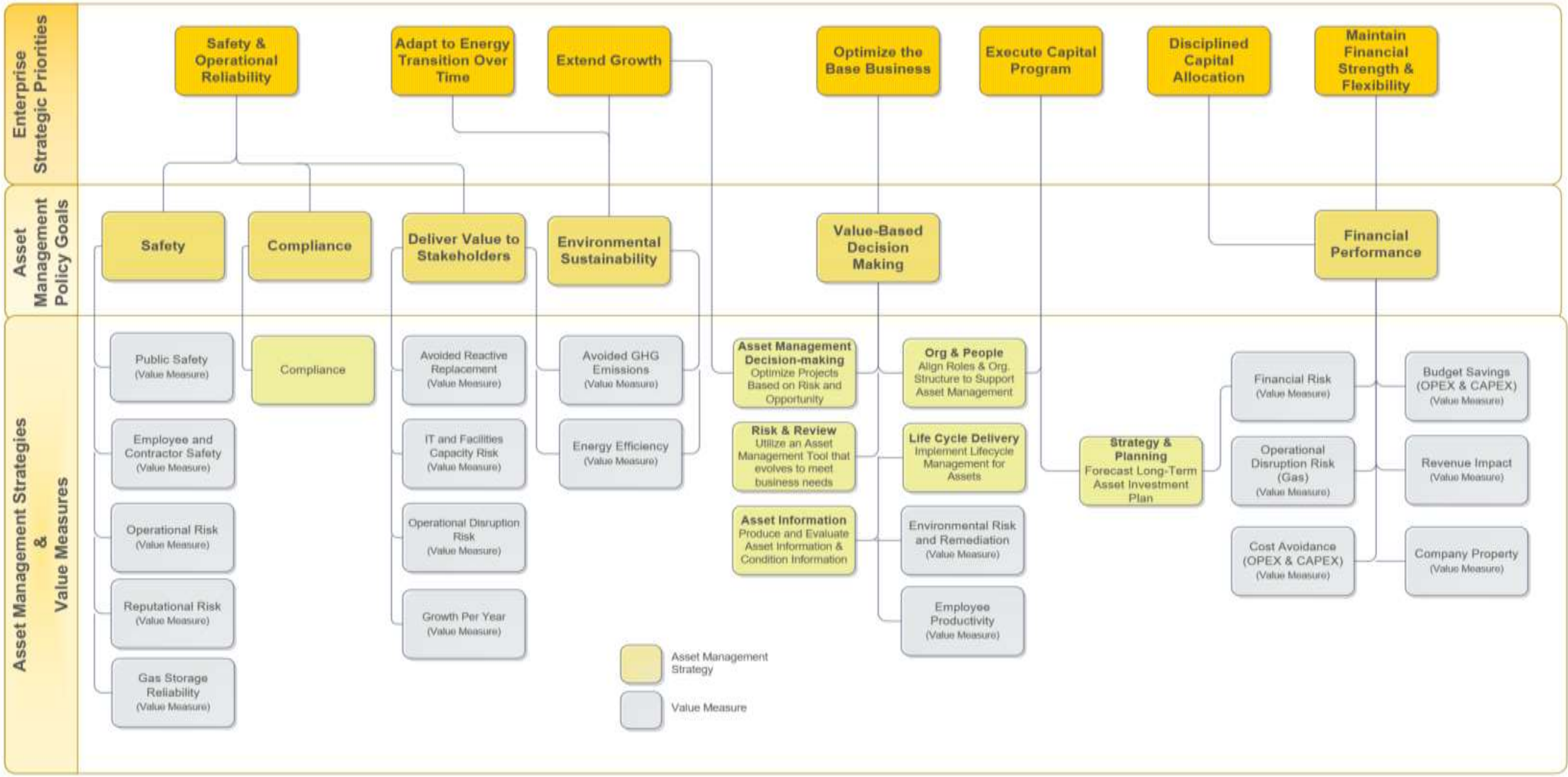

Figure 4.1-10: EGI's Alignment of Enterprise Strategic Priorities and Asset Management Strategies

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4.2 Asset Management Core Process

The asset management core process at EGI is based on Deloitte's Value-Based Asset Management Model **(Figure 4.2-1**) and outlines how EGI's asset management strategies (**Section 4.1**) will be executed.

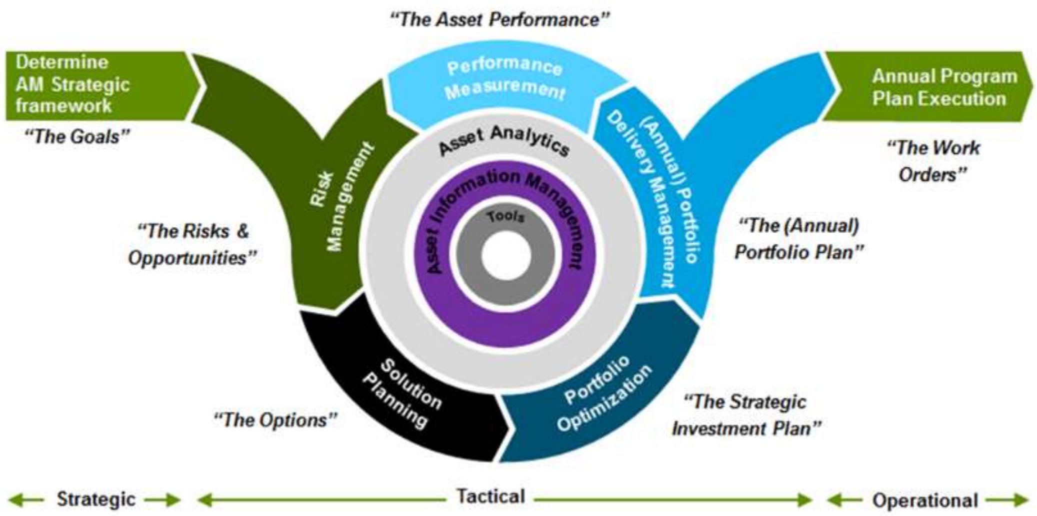

Figure 4.2-1: Value-Based Asset Management Model

Each chevron of the wheel represents a key component in the asset investment management process:

- Determining the Asset Management Strategic Framework (**Section 3**)
- Identifying risks, opportunities and the resultant value-driven investment options
- Developing optimized decisions for the strategic investment plan and annual portfolio plan (i.e., the Asset Management Plan)
- Explaining how asset management performance is measured
- Outlining the tools, data and analytics that support these activities

Within the overall Asset Management Strategic Framework, as investment needs are identified, they are evaluated and executed through the Asset Investment Process (AIP) (**Figure 4.2-2**), based on the chevrons of the core process. This process, as well as the integral role of Asset Analytics, Asset Information Management and Tools (the "inner rings" of the model), are expanded on in this section.

Figure 4.2-2: EGI's Asset Investment Process

4.2.1 Risk Management

The asset investment process begins with an identified Risk/Opportunity that requires an investment. The risk management process is used to assess, evaluate, treat, monitor and report risks identified through a number of different channels. The process also outlines the approach to communicating these risks and seeking endorsement of risk treatment actions to address them (**Figure 4.2-3**).

Figure 4.2-3: Enbridge Risk Management Process

A risk matrix is used (see **Figure 4.1-7**) to provide a consistent basis to assess risks and prioritize treatments. Treatments can be process solutions or capital investments to reduce the risk to a tolerable level and optimize resource expenditure.

4.2.1.1. Identify Risks

Operational hazard and risk identification occur throughout each phase of the asset life cycle. Hazards are identified through:

- Internal sources such as databases, front line processes, targeted reviews, assessments and meetings
- External sources such as published industrial incidents, industry-related publications distributed by regulatory bodies and industry associations, local governments, external crime statistics and industry standards and best practices.

4.2.1.2. Assess Risks

Risks are assessed using several different approaches based on the types of hazards and assets. Assessments can be quantitative, semi-quantitative or qualitative. A risk matrix (**Figure 4.1-7**) provides a consistent basis to assess and report on risks. The most commonly used types of risk assessments used at EGI are described in **Table 4.2-1**:

Table 4.2-1: Risk Assessment Types

Type	Description	Application
Qualitative Approach	General and/or structured brainstorming with a multidisciplinary team to identify and evaluate risks. Relies mainly on qualitative inputs such as expert judgement, experience and technical knowledge.	Used to identify and understand risk factors.

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Type	Description	Application
Quantitative Approach	Detailed technical assessments that leverage numerical data and mathematical methods to quantify risks.	Applied to contexts which are relatively well understood where numerical data and mathematical models can be used to quantify risk factors.
Semi-Quantitative Approach	Relies on qualitative inputs, such as expert judgement, experience and technical knowledge, as well as numerical data and mathematical methods to evaluate risk.	Applied to contexts which are relatively well understood but not all risk factors can be quantified.
Risk value models	Part of C55 value models which quantifies the amount of risk reduced by a proposed solution over the lifetime of an investment.	Used in portfolio optimization.

4.2.1.3. Treat Risks

Risk treatment is the modification of identified risks, ranging from day-to-day operational activities undertaken by operators and field personnel to inspect equipment, to a large capital project to replace an existing asset. Operating inspections, procedures and preventive maintenance activities are developed during the commissioning of an asset and are used to treat identified risks throughout the Utilize and Maintain phases of the asset life cycle. **Figure 4.2-4** lists the risk treatment options used at EGI. The maintenance strategy for a facility or asset is established based on operating standards requirements, the outputs of a maintenance strategy analysis or Original Equipment Manufacturer (OEM) recommendations.

Figure 4.2-4: Spectrum of Risk Treatment Options

4.2.1.4. Monitor Risks

EGI maintains a risk register to communicate and review all operational risks. A risk matrix (**Figure 4.1-7**) provides a consistent communication for all risks, regardless of the risk assessment technique. Risks are reported and reviewed on a quarterly basis through a risk reporting process. Asset condition assessment reports also play a key role in the identification of risks at EGI. Asset managers are responsible for capturing and managing investments and their associated value within their asset class.

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4.2.2 Solution Planning

The solution planning process is initiated through the creation of an investment, occurring in parallel with the value modelling process. An investment contains scope, cost and preferred timing for all identified alternatives (facility and non-facility) to address the need. During the scope development and cost estimation phase of solution planning, methods are identified to address a risk or opportunity (solution alternatives). This requires a clearly defined scope, a proposed earliest and latest start year and the associated cost for each feasible alternative. Investments to address a risk/opportunity could be in the form of a *Project* or a *Program*, as described in **Table 4.2-2**.

Table 4.2-2: Project and Program Descriptions

Investment Type	EGI Description
Project	A one-time individual initiative with a distinct scope and timeline.
Program	An over-arching initiative to address a risk/opportunity that is/will be comprised of multiple projects with varying scopes and timelines.

Cost estimating is an important activity for the solution planning process and the resultant five-year Asset Management Plan. Associated costs of a solution include the direct capital costs, retirement costs and rebillable credits. In addition, any avoided and/or additional operating and maintenance costs are estimated, where known. All estimates are based on current year costs (with the exception of programs that have a defined scope) with an inflation rate applied. Note that scoping and estimating for earlier years of the plan will be more accurate than later years.

All solution options have a cost estimate and the level of accuracy is established using estimate classes, summarized in **Table 4.2-3.** The class of the estimate also informs the level of contingency applied to the project or program.

Contingency is described as the amount of funds budgeted to account for unquantified project costs at the time the estimate is completed; this cost is intended to cover potential risks during execution. Contingency is generally included in estimates with the expectation for it to be expended and is allocated on a project-by-project basis based on asset class, project risk and scope of work.

Table 4.2-3: Estimate Classes

Class	Estimate Description	Scope Maturity	Contingency Level
Class 5	High-level cost estimate	Very Low	High
Class 4	Estimate based on initial information	Low	
Class 3	Estimate based on cost estimating tools and reports	Moderate – High	
Class 2	Estimate based on Request for Proposal (RFP)	High	
Class 1	Estimate based on quote or project completion	Very High	Low

4.2.3 Portfolio Optimization

With value framework and solution planning work complete, portfolio optimization is performed in C55, creating a work plan that optimizes the timing and solutions of all capital projects to maximize the total value of the portfolio. Investments across the entire organization are optimized to determine the highest total value that can be achieved with constraints on annual net direct capital and with available resources.

A five-year timeframe is analyzed to determine the long-term capital forecast. Based on required timing, projects and programs have varying degrees of detail - work details proposed earlier in the plan are more refined than work details proposed towards the end of the five-year span. For this reason, programmatic spend is proposed to address risks. Projects are continually defined and attached to a program as scope refinement occurs.

Once an investment is classified and verified as compliance and/or mandatory based on EGI's defined criteria in **Table 4.1-3**, portfolio optimization begins. Investments identified as mandatory and/or compliance are automatically slotted at the required

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time, rather than using risk and cost to determine optimal timing. Those identified as neither compliance nor mandatory are free to shift within the optimization timeframe.

Prior to optimizing, an initial portfolio representing the preferred option and timing of investments and programs is developed. This typically results in an inconsistent spend profile over the five years, with a much larger proposed spend in earlier years.

Optimization scenarios are determined through the consideration of the following:

- Approved or proposed budget
- Historical capital spend at the organization
- Known intolerable risks, or Very High risks on the Enbridge Risk Matrix (**Figure 4.1-7**)
- Asset life cycle strategies
- The original proposal of work (pre-optimization) and an understanding of the associated compliance and mandatory projects/programs

Using C55, the EGI portfolio is optimized and analyzed by varying the net direct capital per year, highlighting the effects of project timing, option selection and risk. The results from these scenarios are reviewed with asset managers to find the combination of investment alternatives and alternative start dates with the highest possible value within specified constraints.

Based on risk, value measures and the ability to complete mandatory and compliance work, an optimization scenario is selected then reviewed and refined to deliver a final portfolio recommendation. Iterative adjustments are applied and the recommended portfolio is approved once validated against timing and resourcing constraints.

4.2.4 Portfolio Delivery Management and Annual Program Plan Execution

Once the optimized portfolio is approved, it is distributed to all business stakeholders for execution. During project planning and execution, periodic forecasts track project and program costs and reports are generated on actual incurred costs.

EGI acknowledges that the identification of risks and the execution of projects is dynamic. During the year, project scopes may change, or new projects may arise, resulting in cost pressures to the current portfolio. As these pressures are identified, trade-off decisions are made based on risk and available capital, a direct demonstration of EGI's Plan-Do-Check-Act model (**Figure 3.1-2**).

All requests for emerging or revised investments are supported with clear purpose, need and timing, to allow for evaluation. An overall review is conducted to understand various uncertainties and to ensure that as much risk and opportunity is addressed as possible within the constraints of the rate zones. The execution of the annual work plan is monitored and adjusted monthly through the forecasting process and informs the performance of EGI's Asset Management Program.

4.2.5 Performance Measurement

Performance measurement provides insight to asset and asset management performance and the effectiveness of the asset management system. To determine this, four key areas are evaluated:

- The end-to-end asset management process
- Delivery to plan of the approved portfolio (Scope Delivery to Plan and Capital Budget Delivery to Plan)
- Adherence to asset class objectives (**Section 5**)
- Accomplishment of specific asset management objectives

Value is the net present value of an investment, composed of value measure components. **Value measures** are combined to assess and compute the overall value that each investment brings to the organization, considering its financial and non-financial benefits, risk treatment and cost. An investment with a net value less than zero is an investment in which all the benefits specified for the investment have a net present value less than the net present value of the cost.

All value-assessed investments are then optimized in C55 by selecting the combination of start dates and solutions that will bring the highest total value to the organization while satisfying financial, resource, service measure and timing constraints.

While each investment may bring value to the organization, it is not until investments are compared with one another and financial constraints are applied that it is known whether a specific investment will be funded or not, as well as its timeframe. A lower value investment may be delayed in lieu of other, more urgent investments, or may ultimately be deemed unnecessary.

The annual budget process defines capital allocations to investments based on a review of project scope, cost, compliance requirements, risk and value.

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Scope Delivery to Plan is the comparison of the approved portfolio project list to actual projects completed at the end of the fiscal year. Variances are explained to ensure the Asset Management Framework is supporting the reduction of risk and realizing optimal asset value.

Capital Budget Delivery to Plan is informed monthly by the capital forecast. This ensures the governance and controls are in place to optimize the capital plan while operating within an approved budget. It also supports continuous improvement for cost estimating, where the variance between estimate and actual costs are understood and learnings are incorporated in future planning.

Asset Class Objectives have been defined for all asset classes at EGI. These objectives, aligned with asset management goals and principles, outline asset requirements to support successful business operations. Life cycle management is applied across all asset classes to specify strategies that govern decision-making throughout the four stages of the asset life cycle: Design/Construct, Operate, Maintain and Renew/Retire. Adherence to the asset class objectives and life cycle strategies ensures consistent and holistic evaluation of risks and opportunities, setting the foundation for successful asset planning and value realization. Asset class objectives are found in Customers and Assets (**Section 5**).

The **Asset Management Scorecard** will detail specific asset management execution elements supporting the overarching asset management strategies. As asset management is a management program within EGI's Integrated Management System, the asset management programs for the legacy companies are being integrated. As part of this work, an asset management scorecard will be established. The scorecard will inform senior management of the effectiveness of the Asset Management team in maturing the asset management system.

4.2.6 Asset Information, Tools and Asset Analytics

The asset management core process relies on asset analytics, asset information management, and the tools and processes to inform decisions and activities. Like other assets, data requires processes and controls to govern its acquisition, use, maintenance and final disposition. This section outlines the methods and tools (unique to each asset class) used at EGI to manage data and use it for analysis in a fully supported and repeatable way.

One of the prominent components of the Value-Based Asset Management Model is its evidence-based decision-making capability for assets. As assets used for EGI's business functions are diverse, the analytics required to support optimal decision-making along with risk, cost and performance will vary for each asset. Asset analytics aims to use these analytical techniques to make decisions about asset acquisition, creation, utilization, maintenance and renewal/retirement, as well as establish a governance framework around data and analytics to produce consistent and reliable outputs.

The EGI analytical modelling process consists of two broad stages - input data processing and data analysis. Input data for analytical requests can come from various datasets available from internal and external sources. Raw data requires extracting attributes from different data sources, inspecting these attributes for data quality and integrity, managing data issues and transforming the cleansed data attributes to a predefined format to be used in analytics. Once raw data is processed, analyses can begin.

Two broad types of analysis are performed - **Exploratory Data Analysis** and **Analytical Modelling**. Exploratory data analysis uses graphical data displays to summarize and identify data characteristics without using complex mathematical or statistical concepts. Analytical modelling uses mathematical or statistical concepts to analyze data. Analytical modelling is different for each modelling task due to the heterogeneity of assets, data availability and analytical requirements or objectives. Four types of analytical models were used to cater to these heterogeneous modelling needs:

- **Descriptive analytics** uses analytics to provide insight into the past and to answer the question "What has happened?". An example of the type of analysis is analyzing historical work orders from the asset management system to analyze how many corrosion-related failures were observed in the distribution network.
- **Diagnostic analytics** is a form of analytics that examines data or content to answer the question "Why did it happen?". An example of this type of analytics would be identifying root cause for a regulator failure on a sales station.
- **Predictive analytics** uses a variety of techniques to make predictions about the future to answer the question "What could happen?". An example is the creation of leak projections and remaining asset life using reliability engineering and statistical concepts.
- **Prescriptive analytics** helps advise on possible outcomes and to answer the question "What should we do?". An example is the use of C55 to prescribe and optimize asset investment planning for the next five years.

Development of an analytical model is an iterative process that progresses from business understanding to consumption of results. As stated in **Section 4.1.2**, these analytical models are used to extract vital knowledge from available data and support evidence-based decision-making at EGI. Some examples of these outputs are as follows:

- Value framework
- Probability of failure and asset health indices
- Decision support tools

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4.2.6.1. Asset Information Management

Asset information derived from structured and unstructured data, supported by EGI and industry knowledge, is leveraged for asset analytics and modelling to:

- Assess the condition of the asset
- Support and predict risk and opportunity assessments
- Inform and support asset health reviews and engineering reliability assessments
- Establish asset inventory and population over time
- Ensure compliance with EGI policy and regulatory requirements
- Make operational asset decisions, e.g., emergency response
- Ensure safe and reliable operations e.g., core work, maintenance

Data for EGI's assets is categorized as follows:

- **Master data**: Master data captures attributes and characteristics of EGI's assets. Some examples of master data include identification of the asset, location and material/equipment etc.
- **Reference data**: Material specifications and codes are used to classify asset records as they are created and updated.
- **Planning data**: Information such as preventive maintenance plans is used to plan and execute maintenance activities needed to optimize asset performance.
- **Transactional data**: Different interventions on the asset, such as inspection, repair and decommissioning etc., are captured under transactional data.

To ensure the availability of information required for operational and strategic decisions now and in the future, EGI continuously assesses the condition of its asset data through various means:

- **Data quality metrics and reporting**: EGI runs reports according to set schedules on data sets pertaining to the asset classes.
- **Data profiling**: On a periodic basis, statistical profiles of the data housed in key enterprise information systems are generated. Reviewing these results with business users allows for criticality assessments of business data usage and prioritization of data validation activities.
- **Business process evaluation**: On a periodic basis, key business processes producing and consuming asset data (whether recently created or historical) are completed. Data gaps and issues that were identified at different data management stages are ranked and prioritized for remediation based on relative impact on the processes and modelling that use the underlying data.

Generally, asset data captured is fit-for-use for operational process-related tasks (such as construction and maintenance operations), however, it requires further refinement to be used for analytics (such as a risk assessment or an asset health review). Current data management efforts include:

- **Data improvements**: Data corrections to historical records that are not fit-for-purpose are performed on a periodic basis. Data sets are prioritized for remediation according to business needs and process impacts.
- **Records management**: Ongoing efforts to capture unstructured data identifies and catalogues historical installed plant records in content management systems to achieve compliance with records management policies on retention and accessibility.
- **Data governance**: EGI has established a framework introducing policies, principles and standards to implement data governance for asset data. As a part of the framework, data stewards monitor and keep abreast of data quality issues, advise business users on the proper use of data and identify and champion data improvements.
- **Metadata compilation**: Data stewards and other SMAs are engaged in the gathering, drafting and compilation of system data dictionaries and other documentation to capture information about different data sets, improving the use of data to meet specific business needs.

Projects are currently underway or being planned to improve asset data and maintain records management compliance. Findings of these data enhancement efforts will be used to improve the entire asset data life cycle, to complete the Plan-Do-Check-Act cycle of continuous improvement.

4.2.6.2. Tools

Multiple tools are used to store, extract and analyze data, catering to evolving data needs and usage and to support this Asset Management Plan. Different technologies are used in EGI to store master and transactional data. Data extraction tools are used in extracting, transforming and loading data and information residing in different data repositories. Once data is loaded and ready, analytical models are used to support asset management decision-making. **Table 4.2-4** outlines the data systems that hold various forms of asset data (master and transactional) and the different software tools used at EGI.

Table 4.2-4: Data Systems and Tools

System	Description
SCADA	Supervisory Control and Data Acquisition system to monitor and control network operations
Click Mobile	Field mobility solution used to complete Maximo work orders and update asset information
FAST	Tool used to collect condition data at Network Operations sites, combined with other information, to prioritize stations for replacement
Maximo (Gas Distribution)	Enterprise asset management system containing master data on gas-carrying assets, related work and preventive maintenance plans
Maximo (Gas Storage)	Enterprise asset management system containing master data on gas storage assets, related work and preventive maintenance plans
Flagship Navigator, Fleet Element and Fleet Focus	Fleet management software containing information related to vehicles, heavy equipment and tools.
Cloudera, Hadoop	Data lakes used to store structured, semi-structured and unstructured data possessing the capability to store and perform analytics on big data
Oracle	Systems used by Finance to store information related to customers and finances in EGI
SAP-PM	Source of record for stations and Storage and Transmission facilities assets and associated plant maintenance Used to store station-related leak information
ServiceNow	Service management tool containing information and requests related to TIS assets
ArcGIS, Hexagon	Geographical representation of gas-carrying assets Includes modules for leak and cathodic protection surveys
SQL Server	Tool used to extract data from data repositories
Copperleaf C-55	Value framework and investment repository used for portfolio optimization
RiskMaster	System used by Claims and Insurance services to track damage incidents
SAS, Reliasoft, Matlab	Software packages that support advanced analytics and statistical data processing capabilities to perform rigorous analytical tasks
Python	Open source software tool used to automate data and execute extract, transform and load (ETL) tasks
Excel, Access	Various tools are developed on these applications before being migrated to a more robust platform.
Power-BI	Data visualization and dashboarding software tool
IBM - SPSS	Tool used to support the development of decision support tools, failure classification tools, probability of failure models and risk models
PIM - Slider (Pipeline Risk and Integrity Management)	Tool used to determine the expected remaining life of a pipe asset based on in-line inspection data and a crack propagation model
Service Suite	Tool for managing leaks and storing leak history
CORR; GL Essentials	Tool for managing corrosion survey information

5. Customers and Assets

This section provides details on the following for each asset class:

- EGI's customers and the customer growth projections
- Asset class objectives, risks and opportunities
- Asset inventory and condition
- Strategic plans to meet life cycle strategies

EGI delivers energy and related services to about 3.7 million residential, commercial and industrial customers, heating over 75 percent of Ontario homes.

In **Figure 5.0-1**, it can be seen that natural gas delivers a significant portion of Ontario's energy needs on both a peak and average basis. EGI is well-positioned to provide affordable energy and contribute positively to the low-carbon economy through the safe and reliable delivery of natural gas and a commitment to low-carbon alternatives such as hydrogen blending and renewable natural gas. Natural gas continues to be cost-effective when compared to electricity.

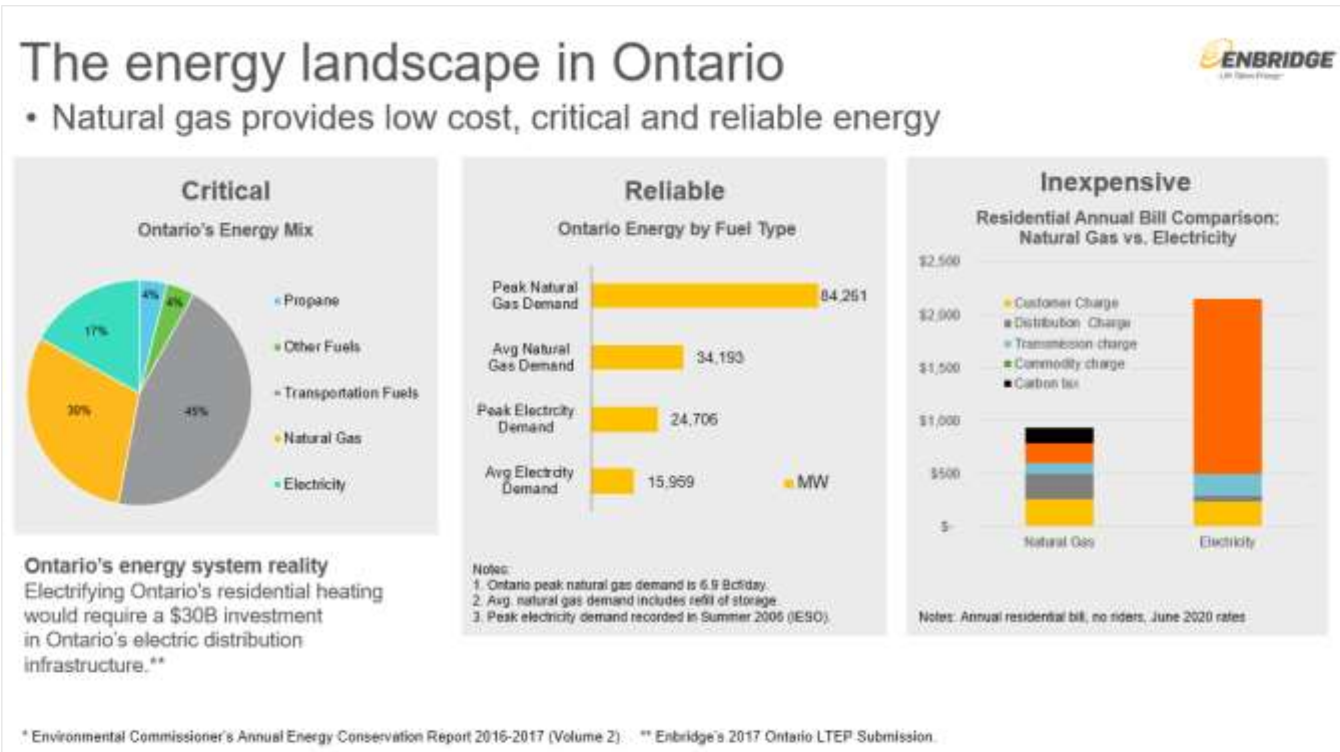

Figure 5.0-1: The Energy Landscape in Ontario

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EGI also provides natural gas storage and transportation services for other utilities and energy market participants in Ontario, Quebec and the United States. EGI's storage and transmission system forms an important link in the movement of natural gas from Western Canadian and U.S. supply basins to Central Canadian and Northeast U.S. markets.

Storage and transmission assets include transmission pipe of up to nominal pipe size (NPS) 48 used to transport natural gas across Ontario, compressor plants to move natural gas to and from storage reservoirs and along the transmission pipelines and a liquefied natural gas plant used to support peak shaving in one area of the company.

EGI's distribution assets include smaller diameter pipe, stations, meters and regulators at homes in the franchise areas. EGI's supporting assets include buildings, fleet vehicles and technology and information services assets across Ontario that support EGI's critical business needs and activities.

EGI has a network of natural gas assets that serve to receive, store, transport and distribute natural gas. **Figure 5.0-2** shows how these assets and those that support them are interconnected to provide safe and reliable natural gas to EGI's customers.

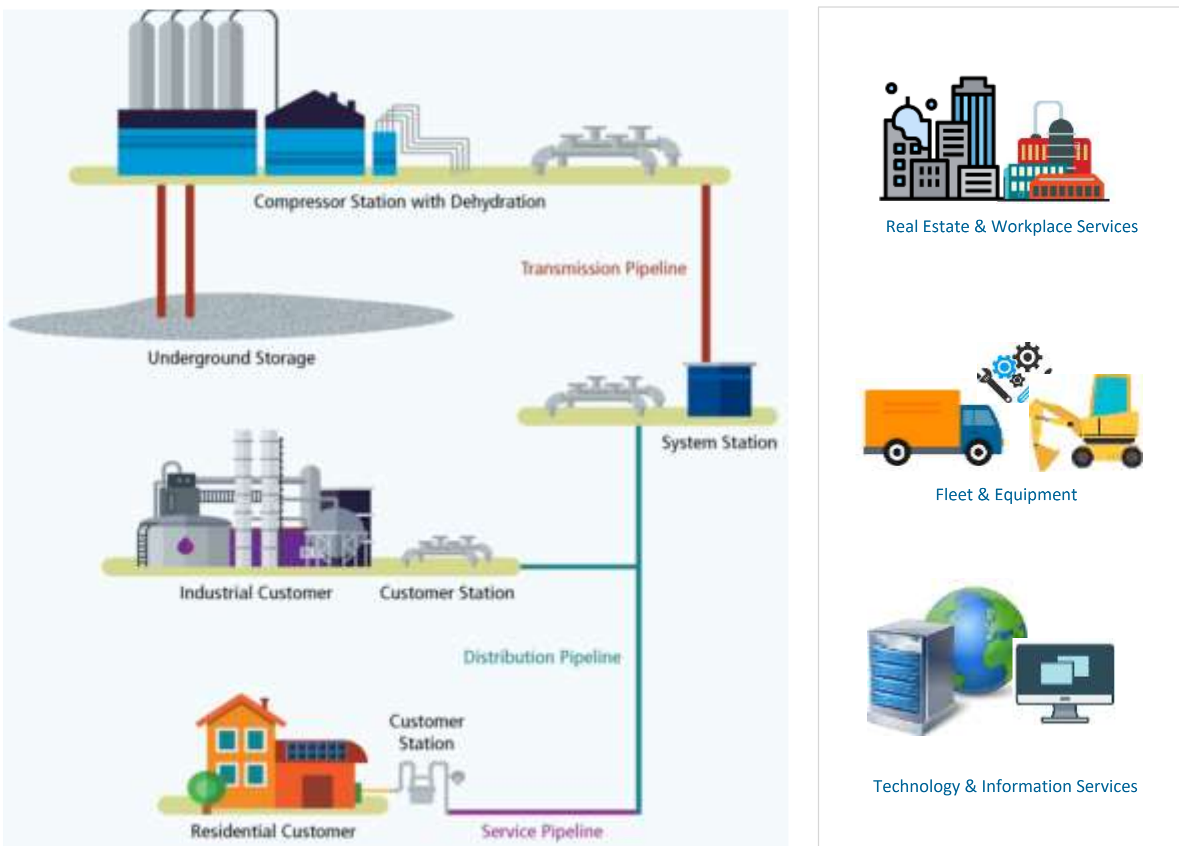

Figure 5.0-2: Components of a Natural Gas System and Supporting Assets

5.1 Growth

EGI delivers safe and reliable natural gas to over 3.7 million customers, forecasted to grow over the five-year period of this Asset Management Plan. EGI services residential, commercial/bulk-metered, multi-family/apartment and industrial customers within its franchise areas.

The Growth asset class consists of the addition of new customers based on new housing or business starts, customers converting to natural gas from another fuel source as well as equipment and service upgrades to accommodate existing customer load growth. The Growth asset class is divided into three asset subclasses:

- **Customer Connections** evaluates customers' natural gas consumption needs and ensures demands are assessed and processed in accordance with the guidelines prescribed in the *EBO 188* report. The assets and costs within this asset subclass include materials and installations of distribution mains, services, meters and regulating equipment.
- **Distribution System Reinforcement** projects involve the installation or modification of existing gas distribution assets to maintain minimum required system pressures, maintain distribution capacity and meet growing natural gas demands. These projects are primarily driven by increased customer demand, customer growth and system reliability considerations.
- **Transmission System Reinforcement** projects involve the installation or modification of existing gas transmission assets to maintain minimum required system pressures, maintain distribution capacity and meet growing natural gas demands in accordance with the *EBO 134* report. These projects are driven by increased transmission interconnect demand as well as increased franchise demand. Capital costs related to transmission system reinforcements are included in the expenditure summary for the Transmission Pipe and Underground Storage asset class (**Section 5.5.8.5**).

EGI continues to evaluate the scope of its carbon strategy and subsequent impact on customer growth forecasts, which includes the Integrated Resource Planning (IRP) initiative. Refer to **Section 3.3** for an overview of IRP activities.

EGI continues to look for ways to reduce its carbon footprint including the introduction of renewable natural gas and hydrogen blending. Risk assessments have been completed as part of project development for these new facilities. As they age, strategies for maintenance and replacement will be established. As government regulations are set and enacted, EGI will continue to respond with programs and projects to meet these requirements with its various existing assets in addition to new assets.

EGI continues to look at ways to extend the footprint of natural gas service within its franchise area, consistent with the requirements of *EBO 188*.

The Growth capital expenditure requirements for materials and asset installation is based on forecasted customer growth over the next five years. Capital expenditure requirements related to the condition of existing assets (mains, services, measurement, regulating equipment, etc.) are addressed in the **Pipe**, **Distribution Stations**, **Utilization** and **Storage and Transmission Operations** asset classes.

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5.1.1 Growth Objectives

The Growth asset class is a key component of the Design/Construct stage of EGI's Asset Management life cycle. It supports EGI's investment in new assets related to customer growth. Growth objectives are listed in **Table 5.1-1.**

Table 5.1-1: Growth Asset Class Objectives

Asset Class Objectives	
System Growth	Ensure an engaged and positive customer experience.
	Ensure EGI provides new or upgraded natural gas services to residential, apartment, commercial, industrial and transmission customers.
	Reinforce transmission systems to economically serve short- and long-term demand requirements.
System Integrity and Reliability	Reinforce existing transmission pipeline systems and distribution networks to ensure capacity and reliably meet current and future customer demand.

The performance measures for the Growth asset class are:

- Number of networks forecasted through the long-range planning process to drop below minimum operating pressure
- Number of customer additions

To achieve the Growth asset class objectives listed in **Table 5.1-1**, asset investment decisions are governed by the life cycle management strategies outlined in **Table 4.1-1**.

5.1.2 Growth Asset Class Hierarchy

The Growth asset class hierarchy is depicted in **Figure 5.1-1**.

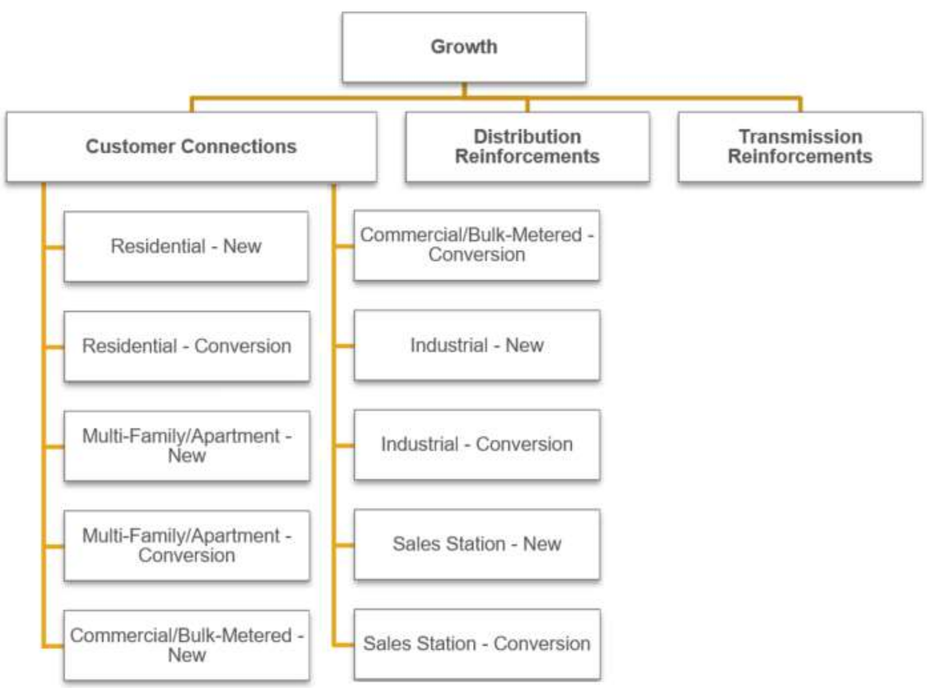

Figure 5.1-1: Growth Asset Class Hierarchy

5.1.3 Growth Inventory

Note: This section only applies the Customer Connections asset subclass.

EGI services residential, commercial, multi-family/apartment and industrial customers - **Figure 5.1-2** to **Figure 5.1-5** profiles EGI's existing customer base by type and location (see **Section 2.3.1** for a map of the EGI operating regions).

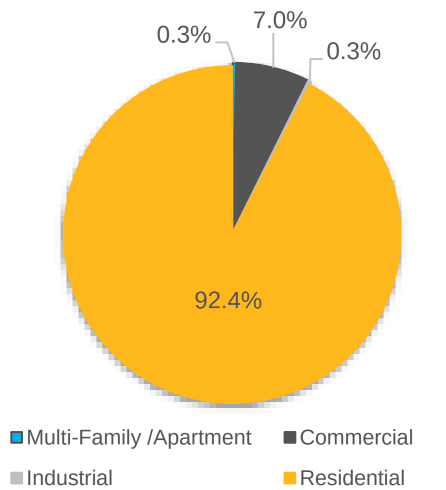

Figure 5.1-2: Customer Breakdown by Type – EGD Rate Zone

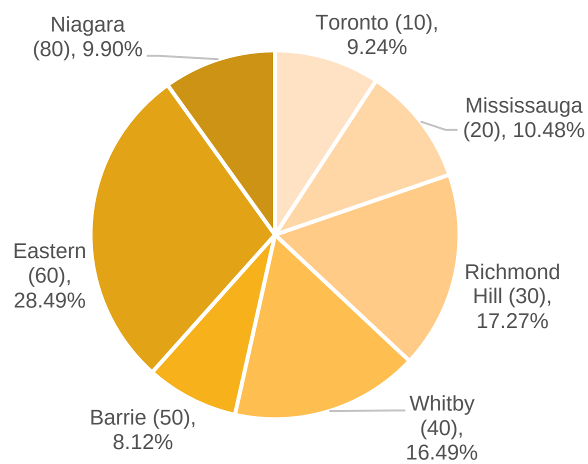

Figure 5.1-3: Customer Breakdown by Area – EGD Rate Zone

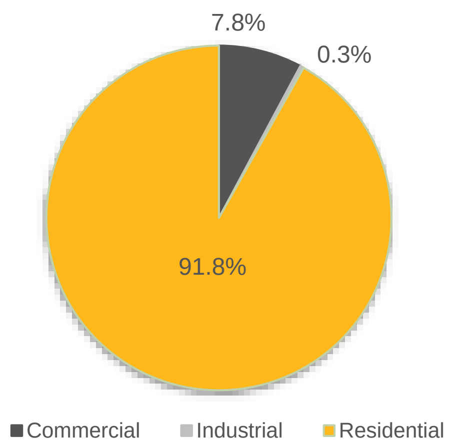

Figure 5.1-4: Customer Breakdown by Type – Union Rate Zones

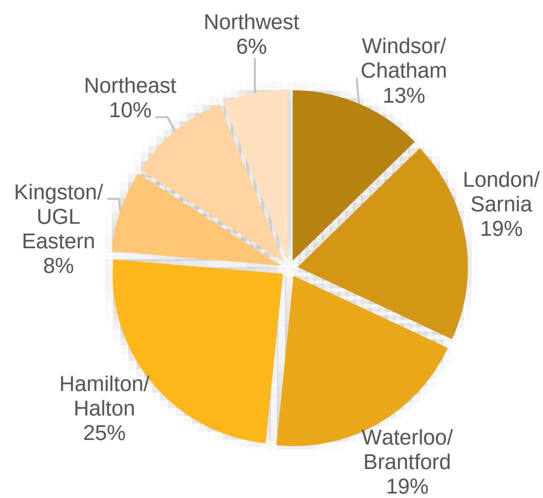

Figure 5.1-5: Customer Breakdown by Area – Union Rate Zones

For the Union rate zones, efforts are underway to recategorize multi-family/apartment customer data to align customer classifications as part of integration activities.

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Table 5.1-2 describes EGI's customer classifications:

Table 5.1-2: Customer Definitions

Customer Type	Subtype	Customer Definition
Commercial / Bulk Metered Uses natural gas for commercial purposes, buying and selling goods or services usually for a profit.	Commercial New Construction	A customer intending to operate a commercial business (including apartment buildings with one bulk meter) in a newly-constructed building and intending to use natural gas to meet energy needs.
	Commercial Conversion	A commercial customer using a fuel other than natural gas for commercial business and is converting to natural gas.
Multi-Family / Apartment Uses natural gas for residential purposes in a large building with multiple residential suites that are individually metered.	New	A traditional apartment customer is a multi-residential dwelling containing more than six units that are metered individually.
	Conversion	A multiple unit residential building where each suite is individually metered.
Industrial Uses natural gas for commercial purposes, manufacturing or processing products.	Industrial New Construction	A customer intending to run an industrial manufacturing business in a newly-built facility and intending to use natural gas.
	Industrial Conversion	An industrial facility using a fuel other than natural gas for industrial purposes and is converting to natural gas.
Residential Uses natural gas for residential purposes.	Residential New Construction	A new residential construction development of homes constructed by a builder for domestic purposes. This includes new subdivisions.
	Residential Conversion	A residential customer using a fuel other than natural gas for domestic purposes and is converting to natural gas.

5.1.4 Growth Condition and Strategy Overview

Asset Subclass	Condition	Risk / Opportunity	Strategy
Customer Connections	Between 2009 and 2019, EGI's customer growth was on average 52,800 customers per year (32,700 and 20,100 for the EGD and Union rate zones respectively). Between 2020 and 2030, EGI's customer growth is forecasted to be more than 40,000 customers annually.	EGI is expected to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers (*EBO 188*), where feasibility is quantified by determining the value of a project's revenues against its costs (the Profitability Index or PI).	The strategy for the Customer Connections asset subclass is to continue to ensure required infrastructure is installed to enable the addition of all forecasted customers that are feasible under *EBO 188* guidelines, while following harmonized forecasting practices. EGI continues to monitor and update the customer additions forecast through the annual long range planning process. Economic feasibility for growth is based on *EBO 188* guidelines applied to the investment portfolio and rolling project portfolio. The service length threshold without any cost to a residential infill (conversion) customers is 20 and 30 metres for the EGD and Union rate zones respectively. For longer services greater than these limits, customers pay a contribution at a rate of $32/metre in the EGD rate zone and $45/metre in the Union rate zones.
Distribution System Reinforcement	Load gathering and simulation, annual forecasting and long range system planning are completed. Areas requiring reinforcement have been identified.	Ensure security of system supply to existing customers and support forecasted customer growth using *EBO 188* guidelines.	The strategy for the Distribution System Reinforcement asset subclass is to implement specific reinforcement solutions in a timely manner to enable forecasted customer growth while maintaining safe and reliable operations. Long-term reinforcement plans are being completed per existing processes and alignment continues as part of integration activities. Integrated Resource Planning (IRP) will be considered based on the outcome of the IRP proceeding currently before the OEB.
Transmission System Reinforcement	EGI's major transmission systems, which include Dawn Parkway System, the Panhandle System and the Sarnia Industrial Line System (SIL) move natural gas from receipt points to delivery locations along the pipeline to meet the volumetric demands and pressure requirements of EGI's in-franchise and ex-franchise customers. The pipeline system forms the foundation for future development as customers' needs grow and represents the supply into many of the EGI distribution networks. The reinforcement process includes identifying the purpose, need and timing of reinforcements, design day demand development, incorporation of corporate growth forecasts, model simulation and short- and long-range planning.	Ensure safe and reliable transmission system operations and support interconnect and end use growth using *EBO 134* guidelines.	The strategy for the Transmission System Reinforcement asset subclass is to implement specific reinforcement solutions in a timely manner to enable forecasted customer growth and to support distribution growth and reinforcement. In some cases, there is a need for transmission reinforcement to serve contract customer growth in the Sarnia Industrial Line, Panhandle and Dawn Parkway systems, dependent on market conditions and ex-franchise transportation demands in Ontario, Quebec, the Maritimes and major U.S. natural gas consuming areas.

** Capital costs related to transmission system reinforcements are included in the expenditure summary for Transmission Pipe and Underground Storage (**Section 5.5.8.5**).*

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5.1.5 Customer Connections

The Customer Connections asset subclass consists of the addition of new customers based on new housing or business starts, customers converting to natural gas from another fuel source, as well as equipment and service upgrades to accommodate load growth of existing customers. These customers are connected in accordance with the feasibility guidelines prescribed in the *EBO 188* report. The assets and costs associated with connecting these customers include materials and installations of distribution mains, services, meters and regulating equipment.

EGI expands its distribution system in accordance with the OEB's guidelines for the expansion of natural gas service. The intent of these guidelines is to facilitate the rational expansion of natural gas service while protecting existing customers from undue cross-subsidization. Factors evaluated include: the number of potential new customers, their gas consumption and the cost of extending gas mains. Details on these requirements are in **Section 5.1.5.1**.

Each year, EGI develops a customer additions forecast using a number of information sources. Details on this process and projections for each rate zone are in **Section 5.1.5.2**.

Capital investments, such as material and labour costs, are required to support new customer connections. Details on the capital investment forecast are in **Section 5.1.5.3**.

A summary of EGI's strategy for connecting new customers is in **Section 5.1.5.4**.

5.1.5.1. Customer Connections Feasibility

EGI uses a portfolio approach (Investment Portfolio and Rolling Project Portfolio) to manage system expansion activities and ensures that required profitability standards are achieved at both the individual project and the portfolio level.

- **Investment Portfolio**: This approach evaluates feasibility on all proposed new distribution customer attachments for a particular test year and ensures required portfolio profitability index (PI) thresholds are achieved. The portfolio includes the costs and revenues associated with all new distribution customers forecasted to be attached in a particular year (including new customers attaching to existing main or infill services). It also ensures there are no undue cross-subsidizations in the short term. The investment portfolio is designed to include a safety margin to mitigate the forecast risk and achieve a PI threshold greater than 1.0.
- **Rolling Project Portfolio (RPP)**: This approach maintains a portfolio of system expansion projects over a rolling 12-month period. RPP is used as a management tool for estimating the future impact of capital expenditures associated with system expansion. RPP excludes customers attaching to existing mains (infill services). RPP is required to achieve a PI threshold greater than 1.0.

The OEB's view, as set out in *EBO 188*, is that by assessing the financial viability of all potential customers as a group (using a portfolio approach), more marginal customers could be served as a result of assessing the cost of serving them together with more financially viable customers.

Feasibility analysis of individual customer connections (i.e. a project) is carried out by using the guidelines prescribed in *EBO 188*. A feasibility analysis determines whether a project meets financial requirements and ensures there is no undue cross-subsidization over the project life cycle. This is accomplished by calculating the profitability index (PI) of the project based on its future revenues versus the costs.

The profitability index is a ratio of a project's revenues against its costs. PI = 1.0 represents the value of a project's revenues being equal to the project's costs. This means that over the life of the project, project revenues will cover the entire project cost, ensuring the project will be economically feasible.

The OEB, through *EBO 188*, expects utilities to maintain a PI of 1.0 or greater at a portfolio level. Each distribution project must meet a PI of at least 0.8 in order to be included in a utility's Rolling Project Portfolio. EGI is recognizing increased costs to add customers as a result of inflation and changes to construction practices to reduce the likelihood of sewer lateral cross bores in the future.

5.1.5.1.1 Feasibility Process

When assessing the feasibility of a new project, EGI prepares a forecast of project costs and revenues. Project costs include materials (e.g. pipe, couplings, meter sets), labour and equipment to install or construct the project. Costs related to reinstatement of the surface (such as road, sidewalk, landscaping) and the ongoing operation and maintenance of the project are also included in assessing project feasibility.

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EGI determines project feasibility using the estimated project costs and revenues. If the present value of project revenues is equal to or greater than the present value of project costs, the project is economically feasible and can proceed to be built. In such a case, over the life of the project, revenues will recover the entire cost of the project. Depending on the size and scope of a project, EGI may be required to submit a Leave to Construct (LTC) application for OEB approval. In approving an LTC application, the OEB may require that EGI meet certain conditions.

When 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). The CIAC is the amount by which the project capital costs must be reduced by the customer to make the project feasible (i.e. to achieve the required PI threshold).

Feasibility Formula:

$$\text{Profitability Index (PI)} = \frac{\sum \text{PV (Revenue} - \text{O\&M} + \text{CCA Tax Shield)}}{\sum \text{PV of Capital Cost}} \text{ or PI} = \frac{\text{Benefits}}{\text{Cost}}$$

The OEB recognizes that the amount charged as a CIAC is project-specific and varies depending on the costs and revenues for each project. The OEB has established feasibility guidelines and a formula for calculating the CIAC. Utilities can only charge a CIAC as prescribed by the OEB in *EBO 188*. If the customer chooses not to pay, the project is not built.

Benefits: The project revenues are based on the monthly customer charges and delivery charges of the forecasted customers and are netted against ongoing incremental operating and maintenance costs of the project.

Costs: Direct capital costs for a project may include materials (pipe, couplings, meter sets, etc.), labour and equipment to install or construct the project and reinstatement of the surface (such as road, sidewalk, landscaping).

Indirect costs for a project may include planning and design costs (Customer Connections, Construction, Network Planning and Land), gas distribution network capacity costs and administration costs attributable to customer growth such as inventory management.

5.1.5.2. Customer Growth Forecast

The customer growth forecast is a projection of how many new customers will be attached to the distribution system over the next 10 years. Information considered in developing this forecast includes development projects originating from direct contact with builders, developers and municipalities as well as economic factors and indicators from reliable third-party data sources. These factors include housing starts forecasts, GDP growth, employment and mortgage rates. EGI has been consistently using this approach, which was approved by the OEB in previous rate applications.

There are important data considerations using this approach. For instance, a primary data source used in predicting growth is historical housing starts from Canadian Mortgage and Housing Corporation. For growth projections particularly in the apartment sector, housing starts are much higher than the customer additions in the sector.

Based on known applications and development projects, a consolidation of forecasts and known projects are used to determine the final customer growth forecast.

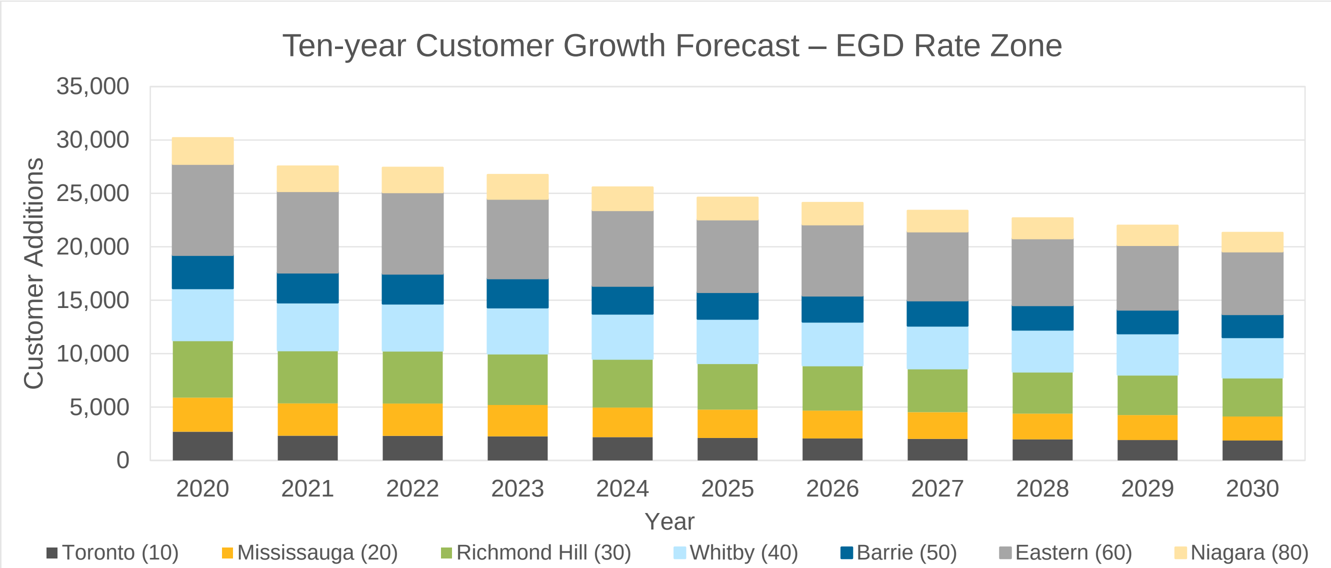

Figure 5.1-6: Ten-year Customer Growth Forecast – EGD Rate Zone

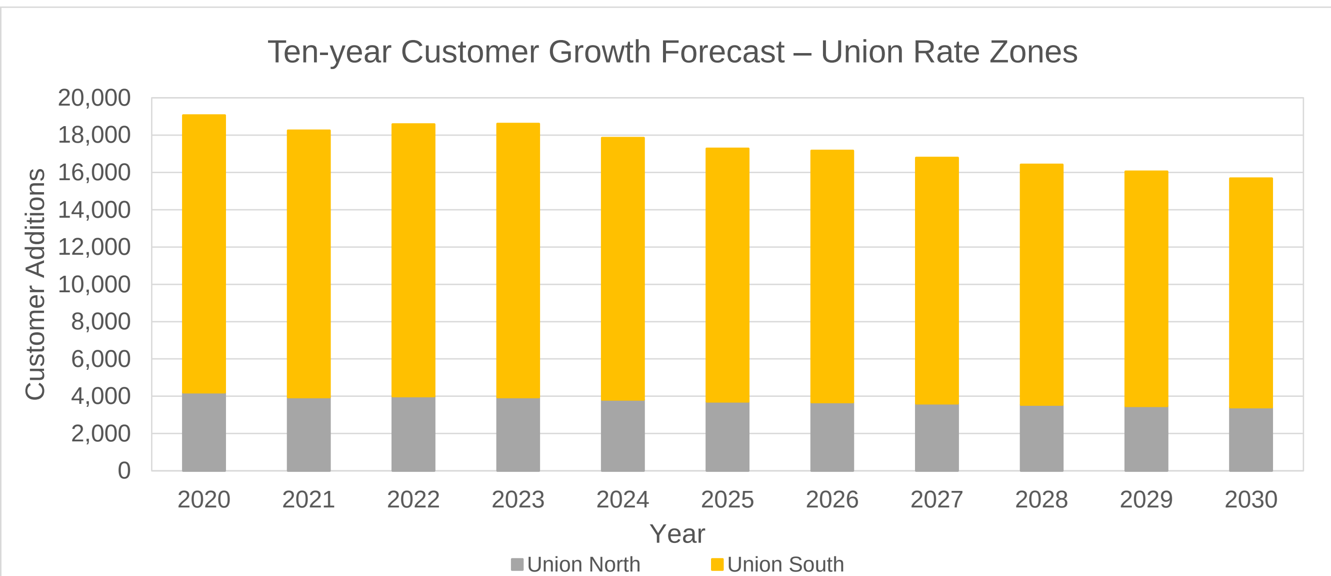

Figure 5.1-7: Ten-year Customer Growth Forecast – Union Rate Zones

In 2019, EGI's customer growth was approximately 44,200 new customers. Between 2020 and 2030, EGI's customer growth is forecasted[10] to be more than 40,000 customers annually. Key insights relating to the customer growth forecast:

- Relative to 2019, housing starts are projected to remain flat in the short term and slightly decline thereafter.
- Due to the increasing scarcity of land supply and the associated increase in housing prices in EGI's franchise areas, particularly in the Greater Toronto Area (GTA), non-apartment housing starts in the area have seen a decline.
- Urban density in EGI's franchise areas is reflected in the fact that apartments have been accounting for a larger share of total housing starts. Given that one building counts as a single customer because of the use of bulk meters, lower customer additions do not reflect lower loads served, but simply a shift in the makeup of the sectoral source of growth.

[10] *Investments based on July 2020 forecast.*

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- Steady residential growth in the new construction sector is reflected in the strong additions in areas covering the GTA, which includes the regions of Peel and York.

Replacement (conversion to natural gas) customers have been declining over the last six years for both rate zones and this trend is expected to continue as demonstrated in **Figure 5.1-8** and **Figure 5.1-9**.

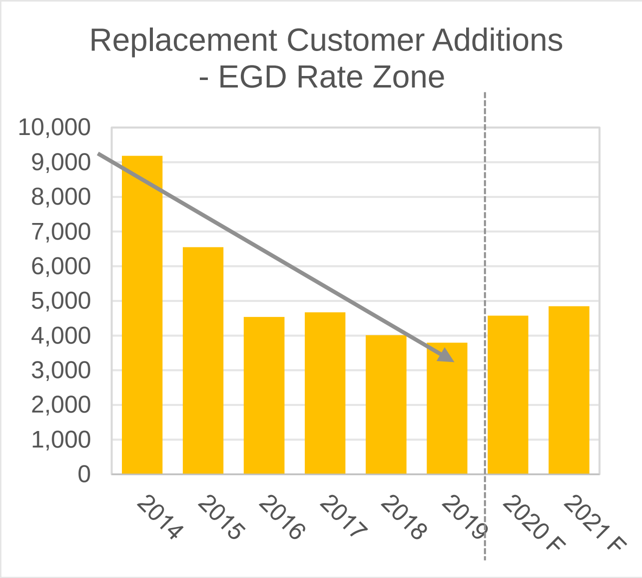

Figure 5.1-8: Replacement Customer Additions – EGD Rate Zone

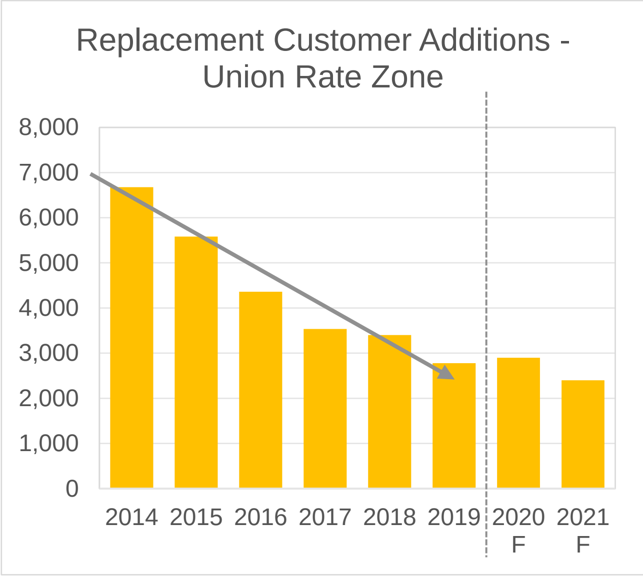

Figure 5.1-9: Replacement Customer Additions – Union Rate Zones

Based on the customer growth forecast methodology described in **Section 5.1.5.1**, **Figure 5.1-10** and **Figure 5.1-11** represent the forecasted number of customers over 10 years by sector.

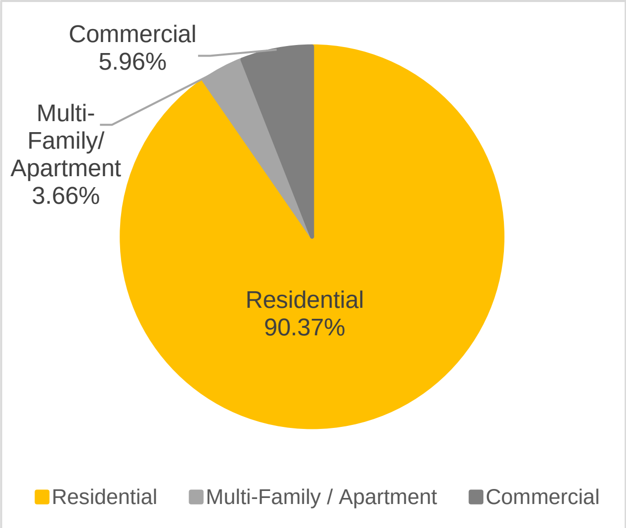

Figure 5.1-10: Ten-year Customer Growth by Sector – EGD Rate Zone

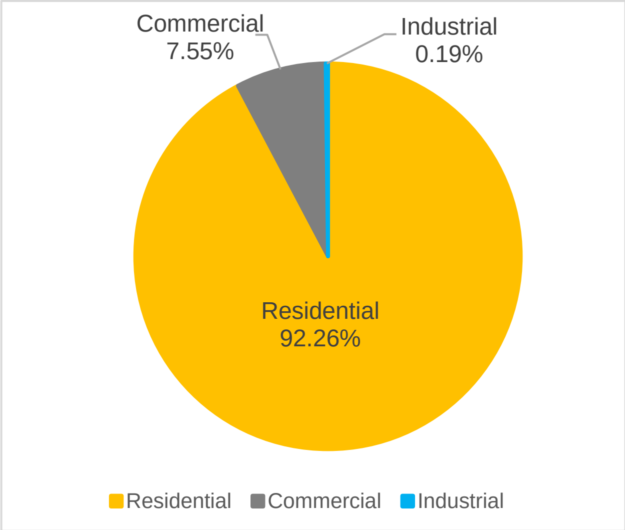

Figure 5.1-11: Ten-year Customer Growth by Sector – Union Rate Zones

The customer additions by sector reflect continued residential growth over the forecast period in both the residential subdivision and residential replacement (conversion) markets, accounting for over 90% of customer additions growth.

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5.1.5.3. Customer Connections Capital Expenditure Forecasting Methodology

Customer Connections capital expenditure requirements include the direct costs associated with the material and installation of mains, services and regulator stations. Meter installation costs are included as part of the direct capital cost within the Customer Connections budget; however, the cost of the metering equipment/instrumentation is accounted for in the Utilization asset class.

Generally, three components of capital investments are needed to support customer addition requirements:

- Material costs related to mains, services and meters. These costs can vary according to size and type of materials.
- Installation costs related to mains, services and meters. These costs can vary according to permits, fees, land rights and construction complexity (e.g. horizontal directional drilling, sensitive environments, geo-technical considerations, proximity to existing infrastructure).
- Costs related to measurement and regulation equipment required to support customer growth.
- Improvements to construction practices to support the long-term safety and reliability of assets

The Customer Connections capital expenditure required to facilitate the connection of new gas customers include:

- Attachments from residential subdivision (Residential New)
- Residential replacement i.e., fuel conversions of existing homes (Residential Conversion)
- Commercial buildings (Commercial New and Commercial Conversion)
- Multi-family/apartment (New and Conversion)
- Industrial facilities (New and Conversion)

5.1.5.3.1 Methodology

One of the key drivers of Customer Connections capital requirements is the historical spend profile in each area. Capital spend is not uniform across all areas, as some areas have inherently higher costs (e.g., hard rock, type of joint trench agreements, densely populated areas and type of customers predominantly being attached). Based on the historical spend in each area, combined with forecast customer additions and inflation, the five-year capital expenditure forecast is determined. The capital requirement includes an allowance for some localized main extensions and operational considerations. Historically, material costs account for 17% and labor costs account for 83% of growth direct capital.

Other capital cost considerations:

- Type of customers requiring connection: each customer class has different infrastructure requirements.
- Type of connection (greenfield vs. urban infill/growth): greenfield expansions are less expensive.
- Joint Utility Trenches (JUT) in greenfield areas save costs and are safer because there is a single excavation.
- Time of year: construction costs in winter months are generally higher and carry winter premium costs.
- Environmental: system growth in conservation areas or green spaces have incremental costs.
- Long term contracts with construction partners can provide cost savings.

5.1.5.4. Strategy Outcomes

The strategy for the Customer Connections asset subclass is to continue to ensure that required infrastructure is installed for the addition of all forecasted customers that are feasible under *EBO 188* guidelines, while following current forecasting practices in each rate zone. EGI continues to monitor and update the customer additions forecast through the annual long range planning process. EGI continues to evaluate the scope of its carbon strategy and subsequent impact on customer growth forecasts, based on the outcomes of the IRP application.

Customer growth forecasts for each rate zone are similar at a high level. However, each rate zone will continue with current methods of preparing a customer growth forecast as part of integration activities. Note that at present, each rate zone maintains separate New Business Policies with a notable difference in the service connection fees, $32/metre after 20 metres for the EGD rate zone and $45/metre after 30 metres for the Union rate zones.

For the EGD rate zone, the OEB ruled in 2019 that EGI must revert back to its previously approved 2015 New Business Policy based on the 20-metre rule and fixed cost per metre thereafter. The capital budget for the EGD rate zone was increased accordingly for 2020 and thereafter to reflect a forecast reduction in the amount of CIACs being collected from customers under the old policy.

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5.1.6 Distribution System Reinforcement

System reinforcements refer to asset investments required to maintain minimum system pressures, so that demand for gas can be met on design day conditions.

Distribution reinforcements refer to investments to the distribution system. These investments must meet the requirements of *EBO 188* (see **Section 5.1.5.1)** or *EBO 134* as applicable. Details on the process for identifying and planning these investments are in **Section 5.1.6.1**.

Distribution system reinforcement projects involve the installation or modification of existing gas distribution assets to maintain minimum required system pressures, maintain distribution capacity and meet growing natural gas demands. These projects are primarily driven by increased customer demand, customer growth, identification of system low pressure points, capacity constraints and other system reliability considerations.

This strategy fosters long-term system reliability and the ability to serve existing and forecasted customers during peak design temperature conditions. Failure to implement reinforcement projects in a timely manner could potentially lead to an inability to support future customer growth and the potential loss of existing customers during peak demand periods.

As part of the asset management planning process, EGI establishes reinforcement needs and timing for all operating regions, ensuring the system meets anticipated peak hourly demand. Load additions to the system are modelled based on design temperatures in **Table 5.1-3** and **Table 5.1-4** for the EGD and Union rate zones respectively.

Forecasting methodologies will be reviewed as part of integration activities.

Table 5.1-3: Temperature Criteria for Load Additions – EGD Rate Zone

Temperature Region	Design Temperature	Degree Day
Peterborough and Campbellford (Area 40)	-28 C	46
Georgian Bay and Barrie (Area 50)	-26 C	44
Ottawa Area (Area 60)	-29 C	47
Greater Toronto Area (Area 10,20,30)	-23 C	41
Niagara Area (Area 80)	-21 C	39

Table 5.1-4: Temperature Criteria for Load Additions – Union Rate Zones

Temperature Region	Design Temperature	Degree Day
Union North		
Northeast		
Zone 1 Fort Frances	-36.7 C	54.7
Zone 2 Kenora	-37.9 C	55.9
Zone 3 Thunder Bay	-33.6 C	51.6
Zone 4 Kapuskasing	-37.6 C	55.6
Zone 5 Timmins	-37.7 C	55.7
Zone 6 Earlton	-37.7 C	55.7
Northwest		
Zone 6 Earlton	-37.7 C	55.7
Zone 7 Sudbury	-33.9 C	51.9
Zone 8 Sault Ste. Marie	-30.2 C	48.2
Zone 9 North Bay	-34.5 C	52.5
Zone 10 Gravenhurst	-31.3 C	49.3
Eastern		
Zone 11 Trenton	-27.7 C	45.7
Zone 12 Kingston	-29.1 C	47.1
Zone 13 Cornwall	-31.2 C	49.2

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Temperature Region	Design Temperature	Degree Day
Union South		
Windsor Operating Area	-25.1 C	43.1
London Operating Area	-25.1 C	43.1
Waterloo Operating Area	-25.1 C	43.1
Hamilton Operating Area	-25.1 C	43.1
Halton Operating Area	-25.1 C	43.1

5.1.6.1. Condition Methodology

Identifying Purpose, Need and Timing of Reinforcements: EGI identifies four major functions required as part of planning for reinforcements: Load Gathering and Simulation, Annual Forecasting and Long Range System Planning.

EGI builds and validates piping system models based on actual field conditions and uses pipeline simulation software to simulate pressures and flows based on customer usage data. Short- and long-term forecasted growth is incorporated into these models to predict system performance.

Load Gathering and Simulation: Load gathering extracts actual billed customer consumption data and matches it with locally recorded temperatures, providing EGI with a reliable, repeatable and predictable method for estimating an individual customer's peak hourly demand. Based on temperature inputs and estimated customer consumption, the base and space heating load demand for each customer is determined and assigned to selected points within the models. For large volume customers, loads are input based on measured hourly consumption and contractual parameters.

The simulation aims to compare calculated performance (pressures and flow rates) of the model versus the actual performance of the system after each winter heating season. Key system settings (i.e., station outlet pressures) in the model are adjusted to simulate actual field conditions on the selected day. The resultant pressure and flow information from the model is then compared with actual field chart or recorder readings throughout the gas distribution system.

Annual Forecasting: Based on the load gathering and simulation model, additional customer loads forecasted for the upcoming heating season are subsequently added. Overall system pressures and station flows are assessed to ensure all minimum pressures are maintained and all stations are operating within design parameters. Locations that are approaching minimum system pressure are selected for pressure monitoring - in some cases reinforcements may be required.

Long-range System Planning: The long-range system planning process considers a minimum of 10 years of customer growth to ensure the adequacy of system performance over the long term. Growth projections are based on information from builders, developers and municipalities, housing starts and other economic factors (e.g., GDP growth, employment rates etc.) as well as projections from external experts. The reliability of the system is dependent on maintaining minimum system pressures and ensuring capacity is available to support customer growth. Reinforcement solutions are considered if minimum system pressure requirements cannot be maintained with forecasted loads applied. Each reinforcement is evaluated considering any or all of the following: existing system capacity, system redundancy or looping, operating pressure, past operational history, integrity, constructability, cost, environmental impact and future expansion or development potential.

Reinforcement solutions are based on the best available information at the time long-range system planning activities are performed. Many variables may change the need, timing or scope of the reinforcement solution. For example, growth may occur earlier or later than forecasted, which may change the timing of the reinforcement.

5.1.6.2. Condition Findings

Long-range system planning activities identify a list of reinforcement projects to sustain the 10-year customer growth forecast. The forecasted customer growth is added to the distribution system provided required reinforcement infrastructure has been installed.

EGI determines the need, timing, location and scope for system reinforcement and quantifies the benefits of the reinforcement using historical and forecasted pressure and capacity at stations and at low points in the system.

Each reinforcement project is summarized in a project brief that details the following:

- **Project Purpose/Need/Timing**: Identification of key drivers affecting the need for the reinforcement, when and where forecasted pressure and capacity constraints will occur and when the solution is required.

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- **Project Benefit**: Overall benefits (quantitative and qualitative) resulting from the proposed system reinforcement include:
  - Security of supply
  - Ability to connect future customers
  - Pressure and capacity benefits achieved
  - Length of time the reinforcement benefits will last before further reinforcement may be required
  - Benefits to system reliability
- **Identification and Evaluation of Project Alternatives**: Description of other feasible facility and non-facility alternatives that may provide similar benefit:
  - Pressure increases
  - Looping strategies that enable multiple network feeds, enhancing system reliability
  - Upsizing of existing pipe, or localized reinforcements to eliminate system bottlenecks
  - Rebuilds of existing stations or addition of new stations
  - Flow biasing
  - Project phasing over time
- **Project Risks if Not Completed:** Description of potential risks to the system if a project is not in service prior to load additions coming online (e.g., insufficient capacity, pressure drops etc.).

5.1.6.3. Risk and Opportunity

Distribution system reinforcement projects identify areas of the network where there is a potential risk of operating below minimum required pressures for safe and reliable operations. This provides EGI the opportunity to develop and manage projects that will provide service to new customers while ensuring continued reliable service to existing customers, the delivery of a low-cost energy source and efficiencies in operation. This aligns with the 2020 Customer Engagement survey results where customers are supportive of investing to maintain current levels of safety and reliability.

Reinforcement projects, which include projects being developed for security of supply and system reinforcement, are governed by the *EBO 188* report. A key principle of *EBO 188* is that existing customers should not have their rates unduly impacted by the costs of connecting new customers. **Section 5.1.5.1.1** provides further details on *EBO 188* guidelines for feasibility purposes.

To meet *EBO 188* requirements, a preliminary feasibility analysis is conducted using cost estimates, forecasted customer additions and discounted cash flow assumptions. This analysis determines the aggregate cost-benefit ratio for all reinforcement projects that are proposed as part of the Long Range Plan (for the EGD rate zone) or Facilities Business Plan (for the Union rate zones). On aggregate, the projects proposed in these plans are in the acceptable feasibility range for inclusion in this Asset Management Plan. Individual projects undergo a detailed feasibility analysis prior to construction to ensure alignment with the *EBO 188* requirements.

The value framework process in the asset investment planning tool provides additional information on risks and opportunities associated with reinforcement projects. For example, the framework can quantify risk reduced by improving system reliability through diversity of supply and quantify the forecasted financial opportunities foregone without reinforcement.

5.1.6.4. Strategy Outcomes

The strategy for the Distribution System Reinforcement asset subclass is to continue to ensure that required infrastructure is installed to enable the addition of all forecasted customers feasible under *EBO 188* guidelines, while following current forecasting practices for each rate zone. EGI continues to monitor and update the customer additions forecast through the long range planning process.

EGI continues to review the distribution system demand requirements through the long range planning process, along with continuous system monitoring. The Long Range Plan (for the EGD rate zone) and Facilities Business Plan (for the Union rate zones) are determined based on the best available information at the time and are subject to change. Changes to the forecasted number of customer additions or changes to forecasted growth locations are captured in the annual forecast review and evaluated against the long range plans. Updates are implemented as required.

Major distribution reinforcement projects reflected in the forecast include:

Rideau Reinforcement

This project will reinforce an extra-high pressure pipeline network servicing approximately 190,000 customers in the Ottawa valley and reduce volumes required from TransCanada Pipelines' pressure-reduced Ottawa lateral. The project involves approximately seven kilometres of NPS 20 pipe extending from Greenbank Road and West Hunt Club Road to Princess of Wales Drive and West Hunt Club Road.

Owen Sound Line Reinforcement

The Owen Sound area continues to grow as retirees move from the Greater Toronto Area. A current reinforcement is underway to supply increasing demands (including EPCOR) in the region - this project is the next phase in reinforcing this network to support forecasted growth. This project will install approximately 28 kilometres of NPS 16 pipe (replacing NPS 8 pipe) from Wellington Road, Harriston to the Durham gate station.

Sudbury Transmission Compressors

The Sudbury system is supported by the Liquefied Natural Gas (LNG)/compressor facility at Hagar. However, the volume of LNG available is insufficient to maintain the system in the event a historical cold winter is experienced. Higher than contracted pressures from TC Energy would be required to offset LNG utilization. This proposed reinforcement project includes the addition of two 2100 HP compressors at Marten River to increase system pressures to support Sudbury system demand. However, alternatives are continuing to be assessed - alternatives include a lift and lay pipeline project from North Bay and upgrades at the Hagar LNG plant.

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5.1.7 Transmission System Reinforcement

In addition to distribution reinforcements, transmission reinforcements are required to support system-wide distribution growth, contract customer growth and depending on market conditions, ex-franchise transportation growth (specifically in Ontario, Quebec, the Maritimes and major U.S. natural gas consuming areas). The identification of the need for a capital expenditure can either be to satisfy a growth requirement or to optimize system performance of an existing asset. In either case, the process to install a new asset is the same. Capital costs related to transmission system reinforcements are included in the expenditure summary for the Transmission Pipe and Underground Storage asset class (**Section 5.5.8.5**).

5.1.7.1. Condition Methodology

EGI's transmission systems move natural gas from receipt points to delivery locations along the pipeline to meet the volumetric demands and pressure requirements of EGI's in-franchise and ex-franchise customers. The pipeline system forms the foundation for future development and provides supply capacity into many of the EGI Network Analysis models.

Transmission systems are designed to meet design day demand to ensure all firm customer demand is served on the design day. Metered data is gathered and analyzed each year to calculate demand assumptions used for system design. Although average annual consumption has been decreasing year over year, EGI has not seen a decrease in design day or peak hourly consumption.

Identifying Purpose, Need and Timing of Reinforcements: EGI completes four major activities to plan for pipeline system reinforcements: Annual Demand Development, Annual Forecast Development, Model Simulation and Short and Long Range Plans.

Annual Demand Development: The Load Cold process analyses daily customer consumption data and local heating degree days to estimate design day demand, providing EGI with a reliable, repeatable and predictable method for estimating customers' design day demand.

Annual Forecast Development: Incremental customer demand forecast for the upcoming winters is added to the design day demand. Various corporate growth forecasts are used including the Facilities Business Plans and the Contract Demand forecast. Customer transportation requirements (including through transportation open seasons) and Gas Supply receipts also form part of the annual forecast development. The Annual Demand and the Forecast Demand are input into simulation models to prepare the Short and Long Range Plans.

Model Simulation: EGI builds and validates the pipeline system hydraulic models used to determine short- and long-range system reinforcement plans. Models are built by extracting pipeline facility parameters from the corporate GIS system and other records. These models are validated by comparing the pressure and flow rates as calculated by the model to the actual field pressure and flow rates. Key system information such as station outlet pressures, flow rates and customer demand in the model are adjusted to match actual field conditions on the selected verification day. The resultant pressure and flow information from the model is then compared with actual field readings. The model parameters are subsequently adjusted to match the simulation to the field parameters.

Short and Long Range Plans: The Short and Long Range Plans are created to plan for the rational expansion of the system. Long Range Plans consider a minimum of 10 years of forecast customer growth to ensure EGI's ability to reliably serve customers' design day demand over the long term. The reliability of the system to serve customers on design day is dependent on maintaining minimum system pressures and ensuring system capacity is available to support customer growth. Reinforcement solutions are considered if minimum system pressure requirements cannot be maintained with forecasted demand applied. Overall system pressures and station flows are assessed to ensure all minimum pressures are maintained and all stations are operating within design parameters. Locations that are approaching minimum system pressure are selected for pressure monitoring–in some cases reinforcements may be required. Each reinforcement is evaluated considering any or all of the following: existing system capacity, system redundancy or looping, operating pressure, past operational history, integrity, constructability, cost, environmental impact and future expansion or development potential. Reinforcement solutions are based on the best available information at the time long range planning activities are performed. Many variables may change the need, timing, or scope of the reinforcement solution. For example, growth may occur earlier or later than forecasted, which may change the timing of the reinforcement.

5.1.7.2. Condition Findings

EGI determines the need, timing, location and scope for system reinforcement. Transmission system reinforcement required for in-franchise customers typically have a long planning lead time while reinforcement for ex-franchise customers can have a shorter lead time as they are driven by different factors.

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No storage growth is forecast for the regulated asset base at this time.

The major contributing factor to EGI's recent infrastructure expansion relates to growth in natural gas production from the Marcellus and Utica shale basins (which are within 300 kilometres of Ontario) and from shippers accessing the Dawn Hub. As a result, the flow of natural gas on the Canadian and U.S. pipeline grid is changing and continuing to evolve.

EGI expects further growth along the Dawn Parkway System driven by further demand growth in the U.S. Northeast and Canadian Local Distribution Companies (LDCs).

5.1.7.3. Risk and Opportunity

The risks identified for transmission reinforcements are operational and financial risks. While the probability of risk is low, the impact–given the criticality of transmission assets to both in- and ex-franchise customers–is very high. The opportunities identified include the ability to provide gas service to meet the needs of new customers while ensuring the continued reliable service to existing customers, the delivery of a low-cost energy source and efficiencies in operation.

Two key aspects to mitigate risk are transmission system reinforcements (as required by demand) and transmission system maintenance (covered in **Section 5.5**). If reinforcements are not completed as required, there is a risk of supply shortfalls (both in- and ex-franchise) on peak operating days. A lack of supply can lead to operational and safety risks as downstream distribution systems may experience pressures below minimum to sustain operations and there could be a loss of supply to customers. As well, if interconnects are shorted, supply to other natural gas franchises can incur customer losses. The financial risks identified are potential lost revenues and possible litigation if contract commitments are not met.

5.1.7.4. Strategy Outcomes

The strategy for the Transmission System Reinforcement asset subclass is two-fold. First, to implement specific reinforcement solutions in a timely manner to enable forecasted customer growth and to support distribution growth (**Section 5.1.5**) and reinforcement (**Section 5.1.6**). Second, growth in the ex-franchise storage and transmission business is driven by economic factors such as exchange rates, interest rates and gross domestic product, but the primary driver relates to changing North American natural gas market fundamentals such as demand and supply, natural gas prices, natural gas basis differentials (the price difference between locations) and North American-wide infrastructure projects. Transmission expansion is completed in accordance with *EBO 134*.

Demand for additional long-term capacity on EGI's major transmission systems is typically met through the installation of new pipeline, station and compression facilities. Non-facility options are also considered, such as using gas supply on third-party contracts for peaking service to optimize resources. Options considered evaluate the effect on system reliability, service quality, security of supply and rates for service.

This Asset Management Plan provides an estimate of future pipeline or compression facilities and does not include any non-facility alternatives or detailed economics for alternative comparisons. If the projects identified proceed, EGI will complete a Leave to Construct (LTC) application containing detailed and rigorous examination of both facility and non-facility alternatives, including detailed costs and economics as required.

Major transmission reinforcement projects are reflected in the forecast:

2021 Sarnia Expansion Project *(EB-2019-0218)*

The 2021 Sarnia Expansion project is driven by in-franchise industrial contract rate growth. EGI filed an LTC application approved by the OEB in March 2020. This project will install 1.2 kilometres of NPS 20 pipeline from the existing Dow valve site to the Bluewater interconnect valve site and to a new LaSalle pipeline valve site. The system capacity generated will primarily serve NOVA's incremental demand and includes some future forecasted growth for the Sarnia Industrial Line (SIL) system. The targeted in-service date for this project is November 1, 2021.

Sarnia Expansion Project- Bluewater Energy Park

Based on a forecasted increase of industrial customers in the Bluewater Energy Park, additional reinforcement of the SIL system will be required. EGI plans to increase capacity through the installation of approximately seven kilometres of NPS 24 or NPS 30 pipeline from the existing LaSalle pipeline valve site to Churchill Road station, expanding customer service and station facilities and increasing SIL system connectivity to the Dawn Hub.

Sarnia Industrial Line (SIL) System

The potential aggregate volume of incremental firm demand in the Sarnia market from all customer interest received to date amounts to more than 250 terajoules per day above the demand stated in the 2021 Sarnia Expansion project (approved by the

OEB in March 2020). The specific volume and timing of these potential demands remains uncertain and cannot be confirmed until firm service contracts are executed with customers.

Dawn to Parkway Expansion (*EB-2019-0159*)

EGI submitted an LTC application to the OEB in November 2019 for the Kirkwall-Hamilton project, which consists of 10.2 kilometres of NPS 48 pipeline from the Kirkwall valve site to the Hamilton valve site, slated for construction in 2022. This project is required to meet increased in- and ex-franchise demands.

Dawn Parkway System

Other than the Dawn Parkway Expansion project (Kirkwall-Hamilton NPS 48) project, future Dawn Parkway System expansion projects are not included in this Asset Management Plan as expansion and timing is primarily driven by changes to North American natural gas market fundamentals. EGI will periodically conduct transportation new capacity open seasons to gauge market demand for transportation services along the Dawn Parkway System. It is anticipated that the next facilities required for expansion are at Dawn to Enniskillen and at Milton to Parkway, which will provide in- and ex-franchise customers additional access to the liquidity, storage and transportation services at the Dawn Hub to meet their market needs.

Panhandle Transmission System Reinforcement

The Panhandle System expansion is driven by in-franchise growth in Chatham-Kent, Windsor-Essex and surrounding areas, including the fast-growing greenhouse market in the Leamington/Kingsville area. Based on the current forecast for in-franchise general service and contract growth in the Panhandle Transmission System market, EGI has determined that the next Panhandle facilities for expansion will need to be in place for the 2028 winter season (construction beginning in 2027).

Panhandle Expansion

This project will install approximately 14 kilometres of NPS 30 or NPS 36 pipeline from the existing Dover transmission station, looping the existing Panhandle NPS 20 pipeline towards the Comber transmission station. Dover transmission station crossover piping will be upgraded and a new tie-in station will be required at the end of the new loop segment. Dawn measurement upgrades will also be required to accommodate gas flows into the Panhandle transmission system. Targeted for 2028.

5.1.8 Growth Capital Expenditure Summary

In the Growth asset class, proposed spending is organized programmatically by sector (residential, commercial and industrial) for the Customer Connections asset subclass. Distribution system reinforcements spending is organized by project. EGI has spent an average of $145M and $140M annually in the EGD and Union rate zones respectively for the Growth asset class. The total average capital spend is forecasted to be $176M (EGD RZ) and $148M (Union RZ) as summarized in **Table 5.1-5** and **Table 5.1-6.** Growth capital is further summarized as part of EGI's total five-year capital plan in **Section 6**.

Note: Community expansion spend is not included in this Asset Management Plan. Capital costs related to transmission system reinforcements are included in the expenditure summary for the Transmission Pipe and Underground Storage asset class (**Section 5.5.8.5**).

Table 5.1-5: Growth Capital Summary ($ Thousands) – EGD Rate Zone

Asset Subclass/Program	2021	2022	2023	2024	2025	Five-year Forecast
Customer Connections	**137,136**	**135,331**	**142,520**	**136,677**	**143,965**	**695,629**
Commercial	24,745	24,399	25,694	24,615	25,910	125,362
Industrial	4,865	4,797	5,051	4,839	5,094	24,645
Residential	107,527	106,135	111,775	107,223	112,962	545,621
Distribution System Reinforcements	**20,318**	**33,933**	**17,315**	**33,636**	**78,604**	**183,807**
Rideau Reinforcement	-	-	344	6,657	62,222	69,222
York Region Reinforcement	3,242	18,733	359	7,792	1,692	31,818
Amaranth System Reinforcement	244	243	-	12,316	-	12,803
Thornton Reinforcement	-	4,464	9,316	-	-	13,779
Low Carbon Energy Project: TOC Hydrogen Blending Facility	**2,667**	**-**	**-**	**-**	**-**	**2,667**
EGD Rate Zone Total	**160,122**	**169,264**	**159,835**	**170,313**	**222,569**	**882,103**

Table 5.1-6: Growth Capital Summary ($ Thousands) – Union Rate Zones

Asset Subclass/Program	2021	2022	2023	2024	2025	Five-year Forecast
Customer Connections	**75,260**	**71,699**	**76,955**	**76,640**	**82,742**	**383,295**
Commercial	-	-	-	-	-	-
Industrial	-	-	-	-	-	-
Residential	75,260	71,699	76,955	76,640	82,742	383,295
Distribution System Reinforcements	**41,688**	**45,454**	**130,447**	**16,998**	**124,272**	**358,860**
Owen Sound Line Reinforcement	-	-	181	5,757	102,718	108,656
Sudbury Transmission Compressors	-	-	66,254	-	-	66,254
Customer Stratford Reinforcement	12,595	3,651	-	-	-	16,246
NBAY: Install 12.5 km of NPS 6, Parry Sound	-	-	19,260	-	-	19,260
LOND: Goderich Transmission System, Reinforcement (11.4 km of NPS 10)	-	-	-	85	2,895	2,980
WATE - Owen Sound Reinforcement Ph 4	2,349	-	-	-	-	2,349
Union Rate Zones Total	**116,948**	**117,152**	**207,402**	**93,638**	**207,014**	**742,154**

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5.2 Pipe

EGI's gas transmission and distribution system operates at a variety of pressures and uses a variety of specifications and materials to achieve the safe and reliable delivery of natural gas to customers. Pipe is the connection between the entry of natural gas into EGI's system and the delivery of gas to where energy is used by customers.

The distribution system takes gas from the higher-pressure transmission system and distributes it to residential, commercial and industrial customers. This is achieved through a series of pipelines of various operating pressures, regulation points that safely manage the pressure of the gas and delivery points where the gas is measured. In some cases, distribution systems are somewhat isolated, serving one or more communities from a single feed from a transmission system.

Pipe includes pipe, valves, all pipe appurtenances, services and risers installed up to Utilization components (typically, assets belonging to the Utilization asset class (**Section 5.4**) begin at the service wing-lock valve). Distribution piping can be located inside or outside of a building.

5.2.1 Pipe Objectives

Objectives of the Distribution Pipe asset class are listed **Table 5.2-1**.

Table 5.2-1: Pipe Asset Class Objectives

Asset Class Objective	Description
System Integrity and Reliability	Maintain the natural gas system to meet or exceed codes, standards and requirements of applicable governmental authorities for safety and operational effectiveness. This includes ensuring the system has the capacity to reliably meet current and future customer demand.
	Ensure the safe and reliable delivery of natural gas to end users.
	Continuously evolve the understanding of condition and risk associated with pipe assets.
	Use risk, cost and performance information to drive asset-related decisions.
Relocations	Relocate pipe assets to reduce or mitigate the impact of planned third-party work on the safe and reliable operation of the distribution system.
	Recover costs allowed by municipal franchises and other agreements for relocations initiated by third parties.

The performance measures for the Distribution Pipe asset class are as follows:

- Density of system (number of customers per kilometre of active main)
- Percentage of leaks reported by leak survey (vs. leaks reported by the public)
- Leaks per 1000 kilometres
- Percentage of cathodic protection (CP) above target
- Number of immediate digs per 100 kilometres
- Number of scheduled digs per 100 kilometres
- Bare and unprotected steel systems (kilometres)
- Pre-1970 pipeline systems (kilometres)

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5.2.2 Pipe Asset Class Hierarchy

Pipe is categorized by material type and the asset subclass hierarchy is illustrated in **Figure 5.2-1**.

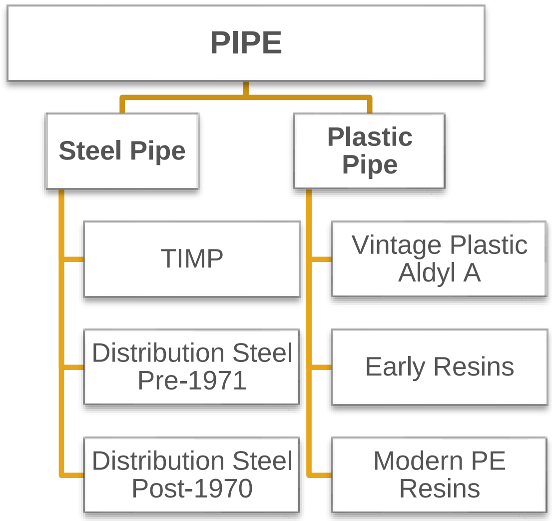

Figure 5.2-1: Pipe Asset Class Hierarchy

Notes:

- Some Pipe asset subclasses (e.g. Distribution Steel Pipe Post-1970) have programs that apply to only a portion of the assets (e.g. bare and unprotected steel).
- The TIMP (Transmission Integrity Management Program) asset subclass is a subset of steel mains that are part of the TIMP in-line inspection (ILI) program or are subject to some other periodic non-destructive assessment of integrity such as external corrosion direct assessment (ECDA). These pipelines either operate at greater than 30% SMYS or have been identified for inclusion in TIMP because of their criticality. A subset of TIMP pipe is included in the Transmission Pipe and Underground Storage asset class and a subset is included in the Pipe asset class.

5.2.3 Pipe Inventory

Table 5.2-2 lists the inventory details for each asset subclass, along with selected other component inventories relevant to certain programs.

Table 5.2-2: Pipe Inventory

Asset	EGD Rate Zone	Union Rate Zones
Mains (km)	**39,116**	**43,895**
TIMP Pipe*	533	2,983
Steel Pipe (Pre-1971)	6,810	10,252
Steel Pipe (Post-1970)	5,870	8,714
Plastic Pipe - Modern PE	20,528	11,647
Plastic Pipe - Early Resins	4,414	1,344
Plastic Pipe - Not yet categorized	N/A	7,620
Plastic Pipe - Vintage Plastic Aldyl A	979	1,335
Select additional asset inventories		
Bare unprotected pipe (km) **	0	162
Copper Services (#)	2,620	0
Copper Risers (#)	26,1973	0

**TIMP Pipe includes assets that are part of the Transmission Pipe and Underground Storage asset class and the Pipe asset class.*

***Bare unprotected pipe is a subset of Steel Pipe (Pre-1971).*

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5.2.4 Pipe Condition and Strategy Overview

Asset Subclass	Avg. Age (Year)	Condition	Risk / Opportunity	Maintenance Strategy	Replacement / Renewal Strategy
TIMP Pipe	EGD RZ: 45 Union RZ: 45	These assets are in good condition. Pipelines are assessed through in-line inspections (ILI) and external corrosion direct assessment (ECDA). Corrosion features are prioritized for immediate or scheduled inspections and addressed within the timeline outlined in the TIMP (Transmission Integrity Management Program).	Risks identified for TIMP pipe: **Employee and Contractor Safety Risk and Public Health and Safety Risk**: Gas pipelines operating above 30% SMYS can rupture, leading to explosion. For lower stress pipelines, gas leaks and migration through underground infrastructure into buildings can result in gas accumulation and explosions. **Financial Risk**: Total repair costs, commodity loss, relighting customer gas appliances, regulatory penalties and any property damages caused by a gas leak **Operational Risk**: GHG emissions, environmental impact and extensive customer outages **Environmental Risk**: Greenhouse gas (GHG) emissions, environmental impact **Reputational Risk**: Unreliable service and customer outages	The maintenance strategy for TIMP pipe includes: • TIMP inspection program (ILI and ECDA) • Vital Main Damage Prevention program • Corrosion Control Operating Standard including cathodic protection (CP) survey • Leak Management Operating Standard including survey program conducted with defined frequency depending on material, age, CP protection and presence of wall-to-wall hard surface area • Valve Maintenance Operating Standard including inspection • Depth of Cover Survey program • Class Location Survey program • Easement Control Operating Standard including easement encroachment and easement clearing • MOP Verification Analysis	The replacement / renewal strategy for TIMP pipe includes: • Maintain code compliance through replacement / renewal work identified by maintenance strategies • Maintain code compliance and reduce risk by addressing immediate and scheduled digs as a result of the ILI findings • Retrofit assets to continuously improve TIMP and migrate to ILI. • Replacement of major pipelines as identified through condition and risk assessment findings
Distribution Steel Pipe (Pre-1971)	EGD RZ: 57 Union RZ: 57	Vintage steel mains have varying degrees of corrosion associated with material, coatings, design requirements, construction practices and maintenance practices based on standards at the time. The condition methodology of distribution steel and plastic mains is common across its asset subclasses. The condition of these assets is determined through maintenance programs, condition assessment programs, tacit knowledge (SMA/worker input) and reliability modelling.	Risks identified for Distribution Steel and Plastic pipe: **Employee and Contractor Safety Risk and Public Health and Safety Risk**: Gas leaks and migration through underground infrastructure into buildings can result in gas accumulation and explosions. **Financial Risk**: Total repair costs, commodity loss, relighting customer gas appliances, regulatory penalties and any property damages caused by a gas leak **Operational Risk**: GHG emissions, environmental impact, service interruptions and reputational damages **Environmental Risk**: Greenhouse gas (GHG) emissions, environmental impact **Reputational Risk**: Unreliable service and customer outages	The maintenance strategy for distribution steel pipe includes: • Leak Management Operating Standard including survey program conducted with defined frequency depending on material, age, CP protection and presence of wall-to-wall hard surface area • Corrosion Control Operating Standard including CP survey • Valve Maintenance Operating Standard including inspection • Bridge Crossing Survey program • Watercourse Crossing Survey program • Vital Main Damage Prevention program (for vital main subset) • DIMP Asset Health Review Program • Condition assessment programs including integrity assessments and material fault reporting to identify and assess failure mechanisms of assets	The replacement / renewal strategies to manage distribution steel pipe includes: • Bare and Unprotected Steel Pipe Replacement program • General Replacement program • Emergency Replacement program • Major discrete replacement project work • Corrosion Prevention program • Development of proactive strategies through integrity studies and sampling programs • Service Replacement program • Copper Services Replacement program • Relocation program (externally-driven)
Distribution Steel Pipe (Post-1970)	EGD RZ: 31 Union RZ: 36	Mains are in good condition, associated with adequate cathodic protection and good coating performance.			
Distribution Plastic Mains Modern Polyethylene (PE)	EGD RZ: 23 Union RZ: 17	These assets are considered to be in good condition. The materials and manufacturing processes support the longevity of this asset.		The maintenance strategies for distribution plastic pipe include: • Leak Management Operating Standard including survey program conducted with defined frequencies • Valve Maintenance Operating Standard including inspection • Watercourse Crossing Survey program • Condition assessment programs including integrity assessments and material fault reporting to identify and assess failure mechanisms of assets	The replacement / renewal strategies to manage distribution plastic pipe includes: • Vintage plastic Aldyl A pipe proactive replacement program • AMP-fitting Replacement program • Service Replacement program • Emergency Replacement program • Relocation Program (externally driven) • Development of proactive strategies through integrity studies and sampling programs
Distribution Plastic Mains Early Resins	EGD RZ: 38 Union RZ: 37				
Distribution Plastic Mains Vintage Plastic Aldyl A	EGD RZ: 44 Union RZ: 38	These assets are considered to be in good condition. However, the failure curve shows a rapid degradation over a very short period of time.			

5.2.5 TIMP Mains

EGI has implemented an Integrity Management Program (IMP) pursuant to Technical Standards and Safety Authority (TSSA) and Canada Energy Regulator (CER) regulatory requirements.

The TIMP (Transmission Integrity Management Program) asset subclass is a subset of steel mains that are part of the TIMP in-line inspection (ILI) program or are subject to some other periodic non-destructive assessment of integrity such as external corrosion direct assessment (ECDA). These pipelines either operate at greater than 30% SMYS or have been identified for inclusion in TIMP because of their criticality. TIMP pipe is included in both the Transmission Pipe and Underground Storage and the Pipe asset classes.

Pipelines with Maximum Operating Pressures (MOPs) resulting in hoop stress levels of 30% SMYS or higher meet the technical definition of "transmission" as prescribed by the *TSSA Oil and Gas Pipeline Systems Code Adoption Document Amendment (Ref. No.: FS-220-16)*. Integrity management of TIMP pipelines represents one of the critical aspects in fulfilling the safe and reliable operation of EGI assets as these pipelines are critical infrastructure for energy markets in Ontario and beyond.

The population of TIMP pipe in the Distribution Operations TIMP portfolio consists of approximately 419 and 1676 kilometres of steel pipe for the EGD and Union rate zones respectively, for a combined length of 2095 kilometres. This includes pipelines operating at >30% SMYS and 50 kilometres of targeted lines operating at <30% SMYS.

The population of TIMP pipe in the Storage and Transmission Operations TIMP portfolio consists of approximately 114 and 1307 kilometres of steel pipe for the EGD and Union rate zones respectively, for a combined length of 1421 kilometres.

The population of TIMP pipelines by decade of installation is shown in **Figure 5.2-2**, illustrating a wide distribution of age for this group of assets. Based on length, over 40% of TIMP pipelines were installed prior to 1970. Despite increasing age, TIMP pipelines are generally in good condition because they are directly inspected and areas of poor condition are replaced or repaired.

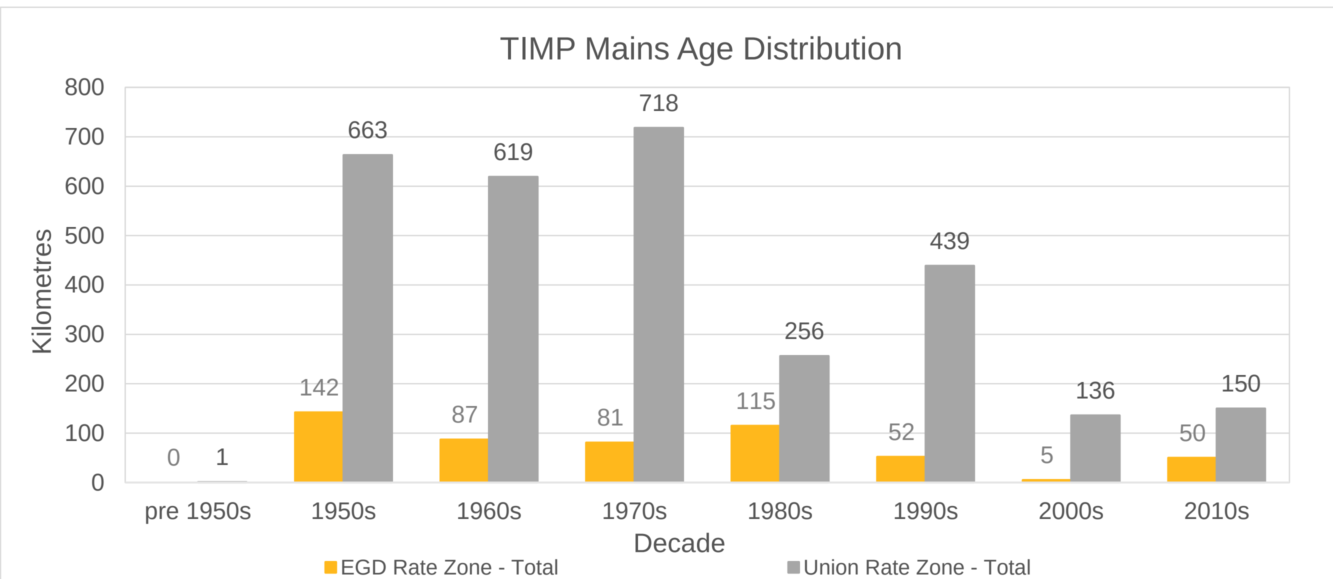

Figure 5.2-2: TIMP Pipelines Age Distribution

5.2.5.1. Condition Methodology

Using engineering analysis and a risk-based approach, the TIMP manages pipeline inspection frequencies and harmonizes inspection schedules to meet compliance requirements and industry-leading standards.

The TIMP is a systematic process for continually assessing and remediating the integrity of pipeline systems through prevention, detection and mitigation techniques. Data is compiled, assessed, validated and analyzed in a comprehensive and iterative manner. Threat mechanisms are understood and risks are assessed through data analytics that establish the

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likelihood and consequence of various types of failures. This facilitates pipeline integrity management activities and optimizes the use of resources to control risk. Threats assessed include:

- External corrosion
- Internal corrosion
- Internal erosion
- Manufacturing-related defects
- Welding/fabrication-related defects
- Equipment failure
- Weather-related threats
- Third party/mechanical damage
- Stress corrosion cracking
- Outside forces
- Incorrect operating procedures

As threats are identified on pipelines, appropriate methods of preventing and detecting threats are used to determine the condition of the asset.

The TIMP employs a reliability-based process, using risk analysis as a tool for developing and prioritizing maintenance on anomalous pipeline features such as corrosion, cracks, mechanical damage and manufacturing defects. These features are identified using in-line inspections (ILI), direct assessments and/or other condition monitoring methods proven effective in the pipeline industry. Features meeting prescribed criteria are subject to further evaluation via direct examinations of pipeline sections through excavation (“digs”) and inspection using non-destructive test (NDT) methods. Pipeline defects found during integrity excavations are repaired before backfilling the exposed pipe.

The TIMP reduces the probability of failure through the inspection and assessment process by detecting and remediating detected pipeline defects.

5.2.5.2. Condition Findings

Many of the TIMP pipelines have been subject to two or more inspections since the inception of the Integrity Management Program. As such, the condition of these assets is generally well understood. Integrity activities on these pipelines typically result from the investigation of time-dependent (such as corrosion) and time-independent (such as third-party damage) events. Improvements in tool technologies further enable the investigation of previous undetectable threats.

In the TIMP program, EGI uses ILI data analysis and risk assessment of pipeline features along with corrosion growth modelling to project known corrosion features of the TIMP pipelines from the last ILI date to future years. This enables excavations to be scheduled prior to corrosion features reaching critical size, accounting for a factor of safety.

The number of digs depends on inspection findings and is an important part of preventing leaks on the TIMP pipeline system. As legacy practices are aligned and in-line inspection is introduced for all pipelines, it is anticipated that the number of digs may increase over the short term before settling into a more stable pattern. For reference, the number of digs over the preceding five-year period is shown in **Figure 5.2-3**.

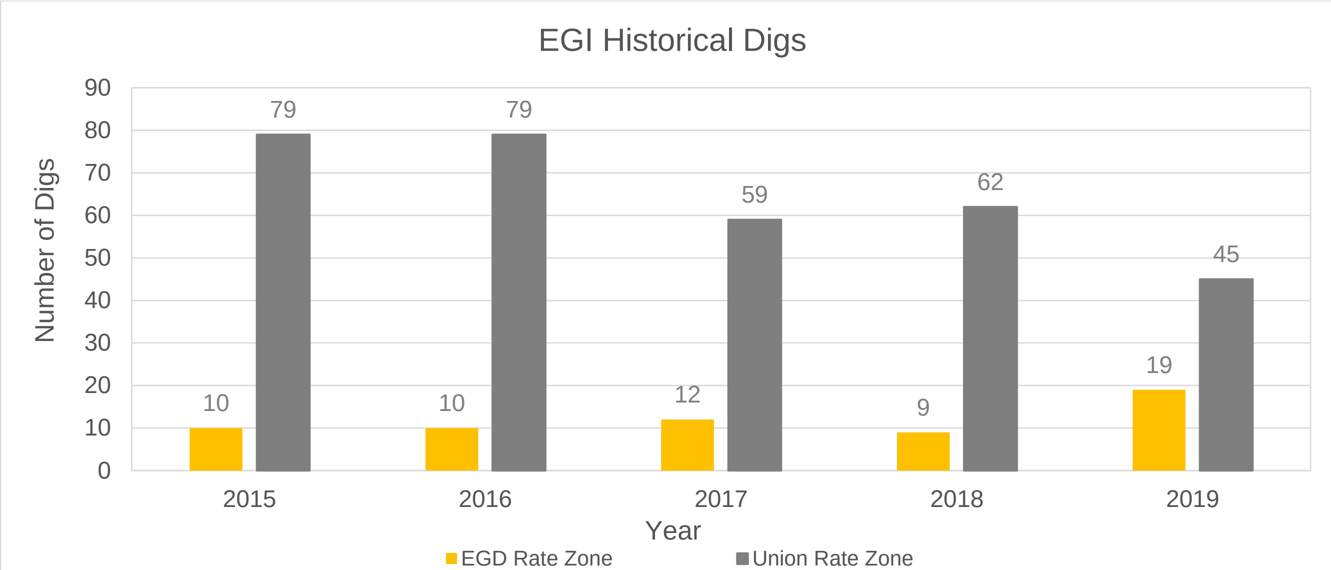

Figure 5.2-3: EGI Historical Digs

5.2.5.3. Risk and Opportunity

TIMP pipelines are critical infrastructure forming the backbone of the EGI system. These pipelines convey gas into downstream networks for distribution, supply large industrial customers (including natural gas-fired power plants) and transport natural gas to major North American markets. Some of these pipelines are located in urban areas and pass through High Consequence Areas (HCAs). Any gas release in such areas could require a substantial emergency response and a temporary shutdown of the pipeline; pipeline failures can pose a risk to public safety as well as gas supply reliability risk.

The risks associated with these pipelines are mitigated through the TIMP by identifying and remediating (as required) pipeline defects prior to failure. These inspections allow EGI to determine whether a pipeline is fit for service and provide quantitative data that can be used to forecast maintenance activities and the expected life of the asset. Understanding pipeline condition allows EGI to make informed decisions on service life extensions. By mitigating immediate and scheduled pipeline features, the TIMP reduces the probability of pipeline failures, reducing the overall public risk and helping to ensure a reliable gas supply to customers.

As a result of the potentially high consequences related to a failure on these pipelines, EGI is retrofitting pipelines with launchers and receivers so that in-line inspections can be used to assess pipeline condition as this technology provides the best data for predicting the condition of the pipeline.

5.2.5.4. Strategy Outcomes

The TIMP pipelines strategy is to continue performing in-line inspections (ILI) and to prioritize additional TIMP pipelines for inspection through retrofits to enhance the amount and quality of condition data. Capital expenditures are required throughout the five-year period to complete retrofits required to inspect previously uninspected pipelines.

Safety is the primary driver for the TIMP, which uses a strategic and long-term risk mitigation approach to ensure these pipeline assets remain fit for service. Inspection data allows EGI to assess system health and helps ensure pipeline safety.

The TIMP contributes to system longevity and is used to extend the useful life of assets by identifying condition issues prior to the occurrence of an incident. The inspections and remedial activities performed through the TIMP reduce the probability of pipeline failures and prevent large scale customer interruptions or unplanned gas releases. The information acquired through inspection is paramount to managing the balance between pipeline repairs and full replacement of TIMP pipelines.

As EGI continues to review operating standards in each rate zone and the use of various materials and fittings, plans will be developed to bring these into alignment in a way that balances risk, cost and performance. This would include but is not limited to the current approach to corrosion management and cathodic protection.

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As EGI further develops and extends its Integrity Management Program, condition issues are identified and assessed to establish the appropriate remediation and timing. Examples that are emerging at this time include depth of cover and exposure of pipelines near watercourses, as well as pipelines that are located on bridge crossings with increased exposure to road salt.

Pipeline program management is evaluated on a continual basis using Plan-Do-Check-Act methodology. When analysis indicates that ongoing repair costs are likely to exceed capital requirements to replace the asset, the mitigation strategy is evaluated to ensure that risk is managed to the lowest practicable level.

The replacement and renewal strategies for TIMP mains are as follows:

TIMP Retrofits and Digs

Investments in TIMP retrofits and digs is mandated by the Integrity Management Program (IMP), a regulatory requirement designed to comply with all applicable codes and standards. The program manages the regular assessment and maintenance of the integrity of EGI's pipeline systems to ensure their continued safety and reliability. Investments in this program include installation costs for ILI inspection tools, retrofits to existing lines and replacement of pipeline segments with integrity issues.

A number of improvements have been implemented since the IMP was introduced in 2002. EGI developed additional criteria and processes to inspect pipelines on a risk-based frequency that considers pipeline operating characteristics and conditions and whether location has an impact on the potential consequence of a failure. EGI also continues to retrofit some pipelines initially assessed through external corrosion direct assessment (ECDA) to accommodate ILI tools and improve integrity assessment completeness. In-line inspection provides the most complete data on pipeline condition and is considered best-in-class for integrity management. Further work has also been completed to reconfigure some previously-inspected pipelines and improve data quality.

Class Location Program

Annual class location surveys are required as per *Canadian Standards Association Z662 – Oil and Gas Pipeline Systems* for pipelines greater than 30% SMYS, unless previously designed, tested, operated and maintained for a Class 4 location. Any changes in class location need to be assessed to the current standard to determine if pipeline modifications are required. Urban development which occurs in close proximity to EGI's pipelines typically triggers class location changes. An annual budget is required for EGI's pipeline system to meet current standard requirements. Remediation includes pressure testing, installation of valves, remediating depth of cover issues and pipeline replacement. This work ensures EGI is compliant and fosters the safety of the public and EGI's pipeline system.

Depth of Cover Survey Program

In compliance with *TSSA Oil and Gas Pipeline Systems Code Adoption Document Amendment - FS-238-18*, EGI has an annual depth of cover survey program for all >30% SMYS pipelines. These surveys may identify locations where remediation is required. The current cycle of depth of cover surveys will be completed in 2023, at which time a prioritized list of capital replacements will be created to plan for any identified pipelines requiring remediation.

MOP Verification Program

Maximum Operating Pressure (MOP) verification is the process of reviewing all existing records for a pipeline system and confirming the maximum operating pressure for pipelines that are at ≥30% SMYS. While this is not currently mandated by code in Canada, it is required in the United States and is expected to become a requirement in Canada in the future. Given that EGI has over 3,500 kilometres of pipelines in this category, MOP verification continues to be a multi-year investment requiring dedicated resources. Spreading verifications over several years keeps costs down and will mitigate the need for higher expenditures in a shorter time frame to meet these expected future mandated requirements. It is also an important assurance activity to maintain a safe and reliable transmission and distribution system.

Through integration, EGI has leveraged the existing MOP Verification Program for the EGD rate zone and is shifting verification program focus to the Union rate zones which is anticipated to result in capital requirements as early as 2023. EGI does continue to use risk to evaluate the priority of the program and adjust the program scope and pacing to allow for the allocation of resources to the highest priority work. While a MOP Verification Program is not yet mandated through regulation, maintaining a balance of varying levels of priority work allows EGI to get ahead of future regulations while allowing for flexibility to reprioritize dollars to highest priority work as it is identified.

5.2.6 Distribution Steel Pipe

The Distribution Steel Pipe asset subclass includes mains (along with associated services and components) covered by the Distribution Integrity Management Program (DIMP). This population consists of approximately 13,000 and 17,000 kilometres of steel pipe for the EGD and Union rate zones respectively, for a combined steel pipe network of 30,000 kilometres. This population is further subdivided into two asset subclasses, Distribution Steel Pipe Pre-1971 and Distribution Steel Pipe Post-1970, due to differences in design, construction and maintenance practices. It is also worthwhile to note that between the early 1950s and early 1970s, steel mains were the only material used in the gas distribution system. These mains operate at different pressure classes and range in size. Note that distribution steel mains do not include pipe covered under the Transmission Integrity Management Program (TIMP). **Figure 5.2-4** and **Figure 5.2-5** illustrate the calendar age of the steel main population for the EGD and Union rate zones respectively.

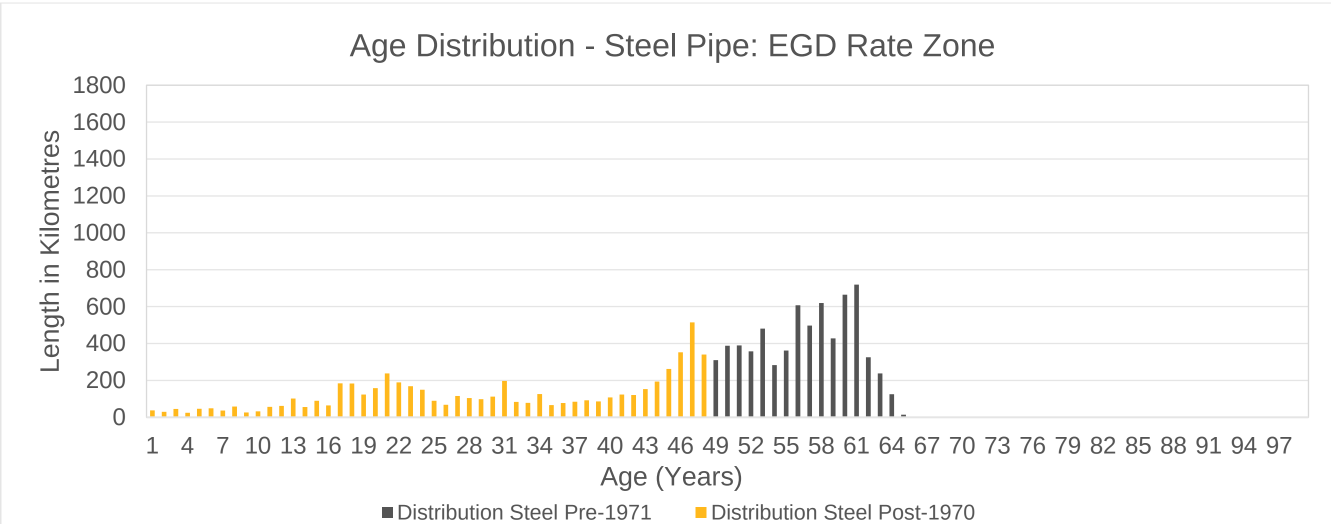

Figure 5.2-4: Age Distribution - Steel Pipe: EGD Rate Zone

In **Figure 5.2-5,** the population spike in 1958 (at age 61) is due to rapid expansion and acquisitions made by Union Gas (e.g., one major purchase was the Dominion Natural Gas Company). Unfortunately, records are not available to adequately classify the installation dates of the acquired assets.

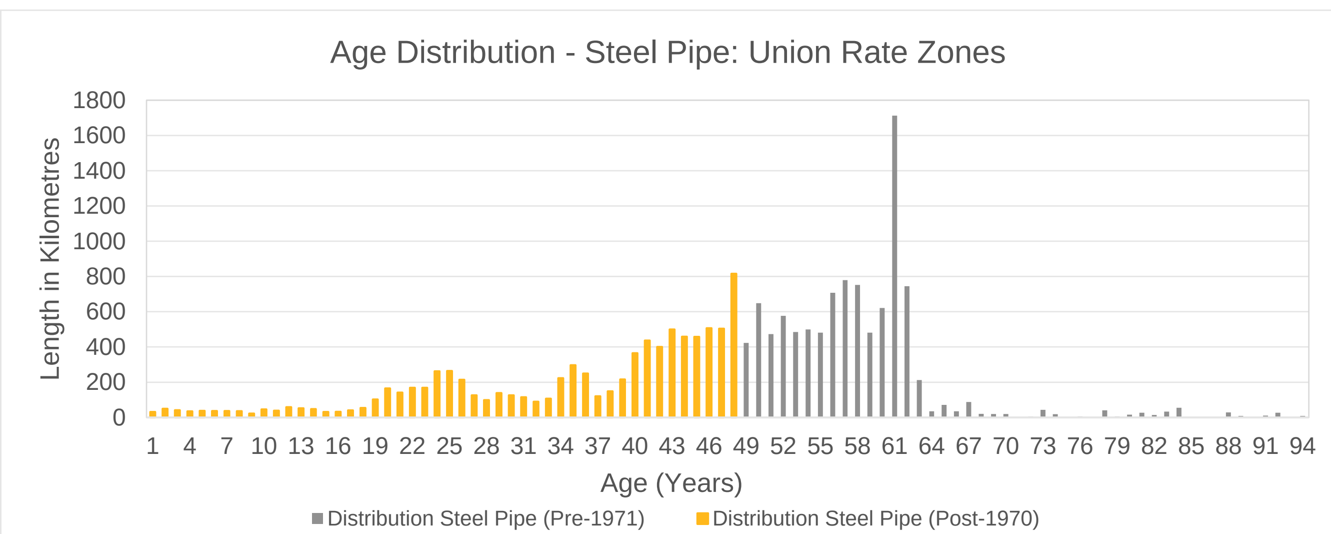

Figure 5.2-5: Age Distribution - Steel Pipe: Union Rate Zones

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5.2.6.1. Distribution Steel Pipe Pre-1971

The Distribution Steel Pipe Pre-1971 asset subclass consists of mains (along with associated services and components) installed in 1970 or earlier and covered by the Distribution Integrity Management Program (DIMP). This asset subclass represents more than 50% of the steel pipe population (approximately 6,810 and 9,200 kilometres of pipe for the EGD and Union rate zones respectively, totaling 16,010 kilometres). These mains were installed using material, coatings, design requirements and construction practices based on standards at the time. Similarly, protection programs such as utility locate and cathodic protection procedures were different from current practices.

Distribution steel mains provide gas to some of the oldest and most populated parts of the EGI franchise area, including the downtown cores of Toronto, Hamilton, London and Ottawa. Over time, urban encroachment and infrastructure activities supporting municipal growth have impacted the condition and consequences associated with potential asset failures. In urban areas, challenges exist in ensuring adequate cathodic protection due to interference from subway, streetcar and light-rail transit systems.

5.2.6.1.1 Condition Methodology

The condition methodology of distribution steel mains is common across its asset subclasses and determined through:

- **Maintenance programs:** These programs (such as Leak Survey and Cathodic Protection) monitor asset conditions and restore assets to their functional state.
- **Condition assessment programs:** These programs (such as integrity assessments and material fault reporting) identify and assess the failure mechanisms of EGI's assets.
- **Tacit knowledge (SMA/Worker input):** Field knowledge is used to identify potential condition issues through regular meetings with subject matter advisors (SMAs).
- **Reliability modelling:** One of the major threats to steel mains is corrosion. A reliability model accounting for pipe attributes has been developed through the Asset Health Review (AHR) program under DIMP to forecast the number of corrosion leaks based on statistical analysis of corrosion leak history from the past 10 years (including factors that accelerate degradation).

5.2.6.1.2 Condition Findings

Distribution Mains

Based on the condition assessment methodologies outlined in the previous section, **Table 5.2-3** outlines the condition findings generally associated with assets in the Distribution Steel Pipe Pre-1971 asset subclass.

Table 5.2-3: Condition Findings for Distribution Steel Mains Pre-1971

Issue	Description
Corrosion	Over time, coating degradation and poor cathodic protection can cause corrosion, resulting in wall loss. Some components that are particularly susceptible to corrosion are: bare and unprotected steel mains, isolated steel mains and headers and mains with vintage coatings–for example, coal tar coatings can disbond and cause shielding. Below-grade threaded connections are also susceptible to corrosion.
Compression Couplings: Pull-Out	Compression couplings (mechanical fittings not welded onto the main) that are not properly restrained can cause a loss of containment due to exposed points of thrust. Compression couplings are held in place by the weight of the soil. When the soil is disturbed, the pipe can pull out of the fitting, resulting in gas escaping through the open pipe end. Some vintage gas mains (such as the Kipling Oshawa Loop (KOL) main) do not have sufficient records identifying the existence and location of these fittings. EGI has mitigation practices in place to address existing known compression couplings.
Compression Couplings: Corrosion	Compression couplings on steel mains can be susceptible to external corrosion and lead to an increased risk of leaks.
Depth of Cover	Reduction in the original depth of cover due to urban development or initial poor depth of cover due to construction practices at the time of installation can increase the potential for

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Issue	Description
	damages due to excavation activities and increased external loading. A minimum depth of cover is needed to ensure the maximum weight of vehicles traversing across pipelines is not exceeded. If the depth of cover is not appropriate, excessive pipe stress and failures can result (see **Figure 5.2-6**).
Bridge Crossing: Corrosion	Continuous exposure to road salt and seasonal ground movement on bridge crossing assets can result in accelerated corrosion and external loading/stresses (see **Figure 5.2-7**).
Pipe Casing: Corrosion	Casings may cause a short with the carrier pipe if the spacers or internal integrity of the casing degrades over time. Many casings in the EGI network lack test points, preventing monitoring for shorts.
Seam Welds	Manufacturing defects associated with seam welds and fittings are weak points in the distribution system and can result in a loss of containment due to prolonged exposure to stress and corrosion (**Figure 5.2-8** and **Figure 5.2-9**). Low frequency Electric Resistance Welded (ERW) pipe (used up to the early 1970s) can also pose a hazard through the potential of cold welds, weakening bond lines and leading to brittle-like failures. Defects in low frequency ERW pipe welds have ruptured at operating pressures below 30% SMYS.
Third Party Damage: Appurtenances on Pipe	Any appurtenances which protrude from the surface of the main are susceptible to damage during excavation activities, as their depth of cover may be significantly less than that of the main. Steel drips (**Figure 5.2-10**) with a protruding drip rod that extend vertically towards the surface and shallow blow-off valve assemblies are examples.
Latent Third-Party Damage	Unreported, latent damages to pipe coatings can become active corrosion sites and can reduce the effectiveness of the corrosion protection system, resulting in accelerated corrosion and potential loss of containment.

Figure 5.2-6: Shallow and Embedded Gas Main due to Road Grade Change

Figure 5.2-7: Severe corrosion on bridge crossing pipe

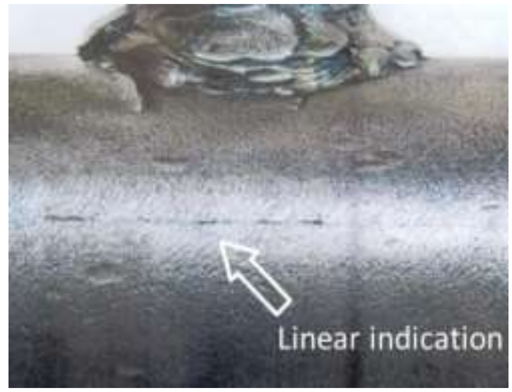

Figure 5.2-8: Vintage NPS 2 steel main with linear indication along weld seam

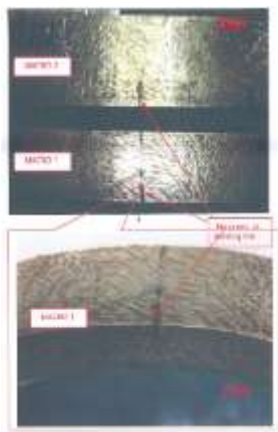

Figure 5.2-9: Inclusion at pipe weld seam on vintage NPS 2 gas main

Figure 5.2-10: Damaged drip rod on vintage NPS 2 gas main

Failure history for the Distribution Steel Pipe Pre-1971 population is shown in **Figure 5.2-11** and **Figure 5.2-12** for the EGD and Union rate zones respectively.

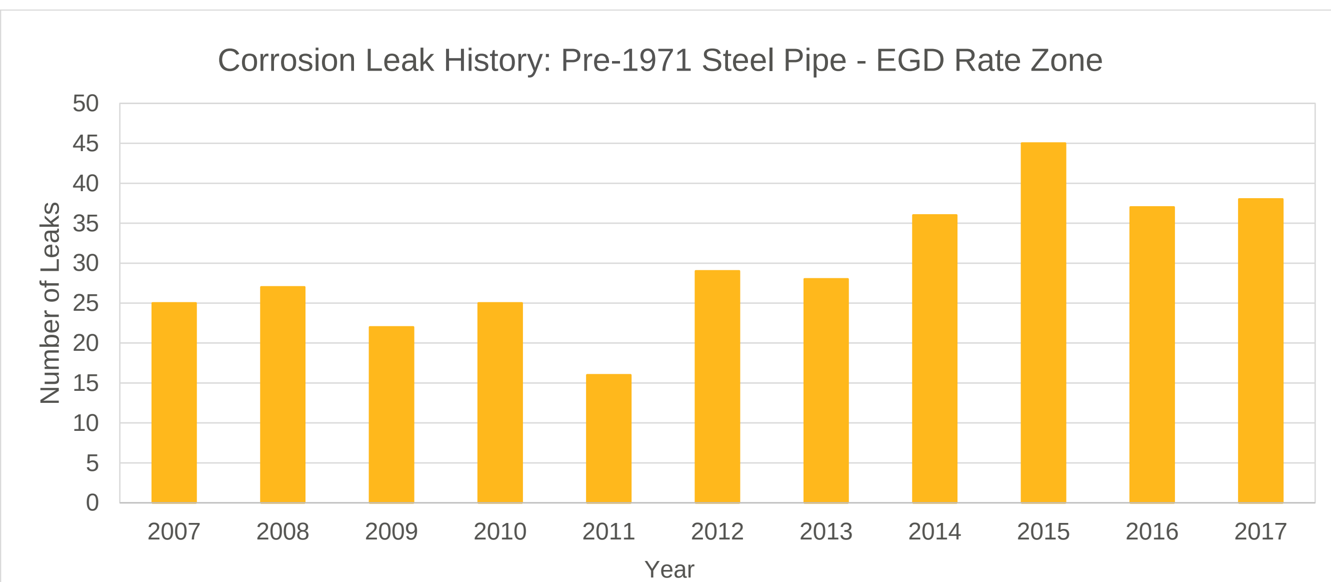

Figure 5.2-11: Corrosion Leak History: Pre-1971 Steel Pipe - EGD Rate Zone

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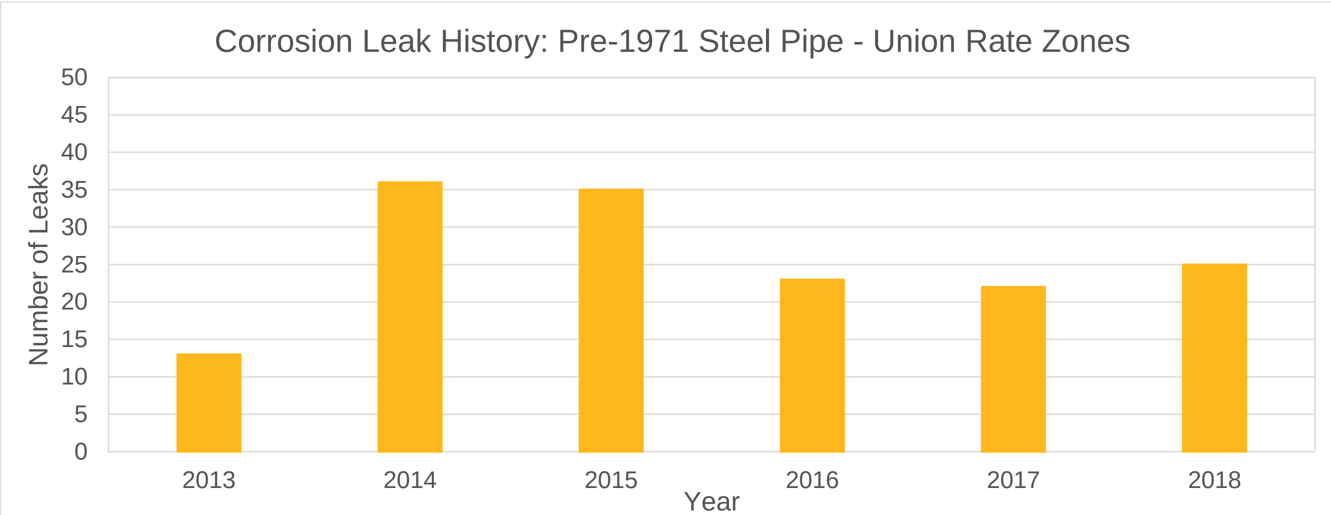

Figure 5.2-12: Corrosion Leak History: Pre-1971 Steel Pipe - Union Rate Zones

The failure history is shown over the 2007-2017 timeframe for the EGD rate zone (**Figure 5.2-11**) and between 2013-2018 for the Union rate zones (**Figure 5.2-11**). Irregularities are most likely due to the mix of assets being leak surveyed in a given year and the survey cycle (typically a five-year cycle for the EGD rate zone and a seven-year cycle for the Union rate zones, with exceptions for certain circumstances). The survey is optimized for geography and efficient execution, rather than leveling the number of leaks found. Note additional differences in the origins of these two charts:

- **EGD Rate Zone**: Leak repair data was analyzed to classify leaks to the failure type (i.e. leak), failed component (i.e. pipe) and failure cause (i.e. corrosion), as part of reliability modelling within DIMP.
- **Union Rate Zones**: Leak repair data was analyzed for location (i.e., above-grade vs below-grade), operating pressure, pipe diameter and others. Open leaks (i.e., C-leaks) are excluded from this data set.

As leaks are closed and data is further analyzed in a consistent manner across EGI, it is likely that the historical data will change. As the analytics practices are aligned for reliability modelling within DIMP, the trends and predictions will evolve and become increasingly reliable.

Reliability modelling within DIMP (currently only available for pipe assets in the EGD rate zone) is used to project the annual number of leaks on pre-1971 distribution steel mains over the next 20 years (see **Figure 5.2-13**). Projections assume no change to maintenance practices in the EGD rate zone (namely, that most steel main leaks are mitigated via repair within a relatively short period of time and a small number of leaks are eliminated when the pipe is replaced). As maintenance practices are updated as part of utility integration, these models will also be updated.

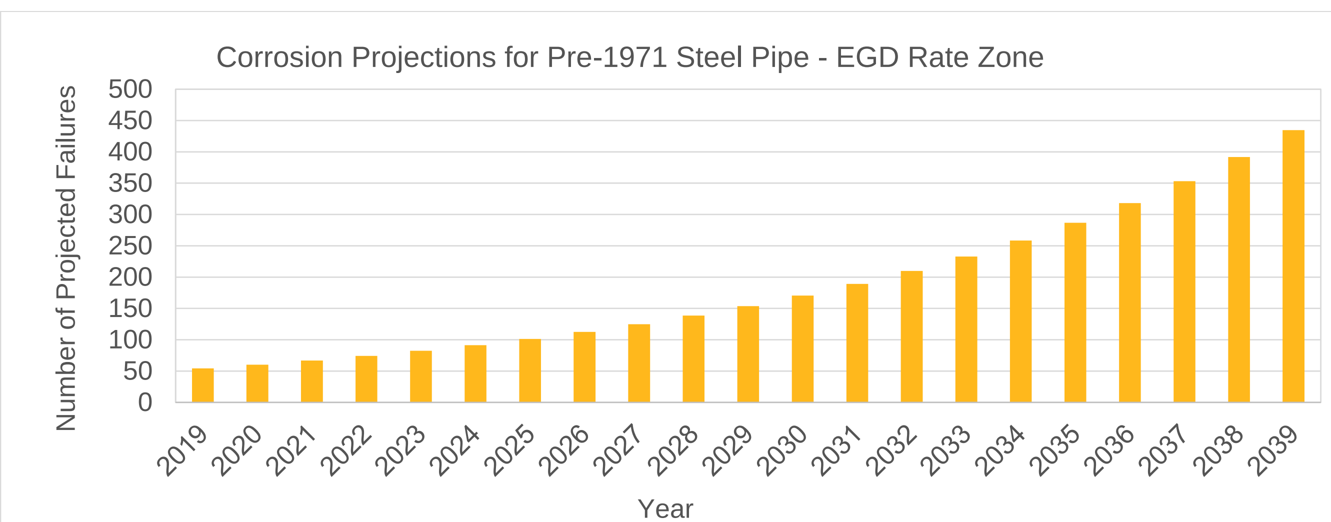

Figure 5.2-13: Corrosion Leak Projections for Pre-1971 Steel Pipe – EGD Rate Zone

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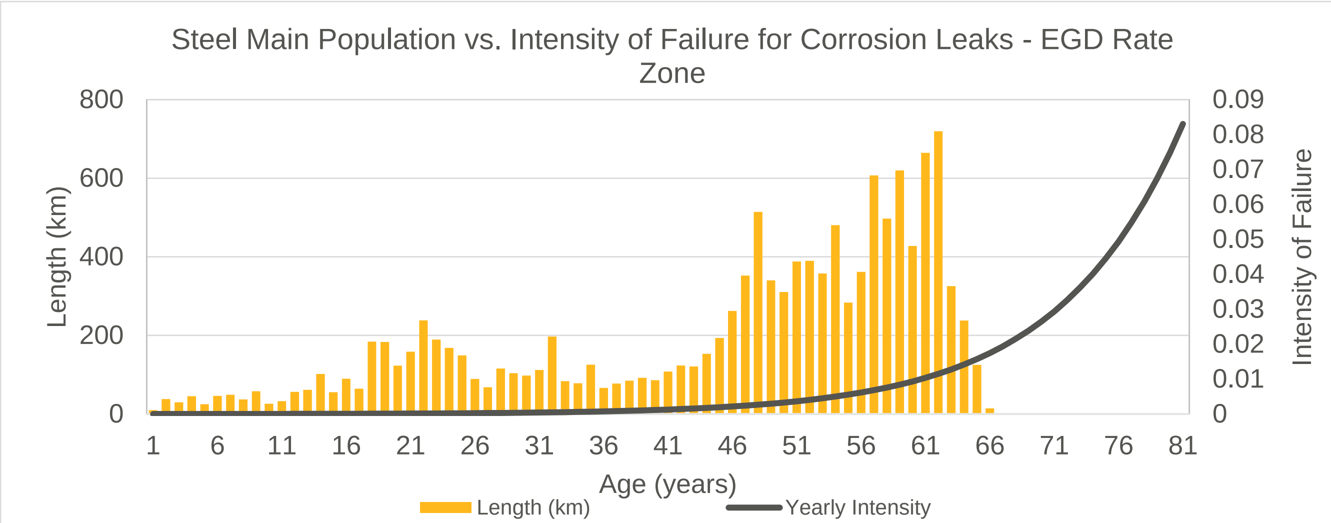

Figure 5.2-14: Steel Main Population vs. Intensity of Failure for Corrosion Leaks - EGD Rate Zone

The steel main reliability model forecasts the number of annual leaks will increase steadily over the next 20 years. **Figure 5.2-14** shows the cumulative length of pipe for a given age. By 2039, the number of leaks will have increased by approximately tenfold. This represents an exponential growth in the number of leaks. Although the above graphs represent projections specifically for the EGD rate zone, vintage steel pipe in the Union rate zones is expected to behave similarly.

The significant increase in corrosion leaks is forecasted to take place as a portion of the mains population approaches 100 years of age–this occurs between 2037 and 2057. **Figure 5.2-14** shows a sharp increase in failures per year as the mains approach 100 years of age which could be due to multiple coating defects along the pipe body and poor cathodic protection history. Coating defects can result from manufacturing defects, field applied coating anomalies, coating degradation from environmental factors or third-party damage.

To validate the reliability model, corrosion rates predicted by the model were compared to rates derived from in-line inspection (ILI) data on TIMP mains (see **Section 5.2.5**). The corrosion rates predicted that TIMP mains would experience at least one corrosion leak before reaching 100 years old if scheduled digs were not performed to mitigate defects. This result is consistent with projections of the distribution steel main reliability model. It is important to note that some steel mains could experience more severe corrosion due to exposure to multiple influencing factors, such as coating damages, poor cathodic protection and aggressive soil/ground condition, leading to the conclusion that leaks could occur well before the age of 100.

Although reliability models were not previously used to provide failure projections for Union rate zones assets, work is now underway through DIMP to include all distribution assets into the reliability modelling work, which is expected to take multiple years to complete.

Pipe coatings used on pre-1971 steel pipe (like coal tar and field-applied coatings such as mastic wrap) can get brittle over time and are susceptible to cracking and disbondment, allowing for corrosion to occur. As an example of a corrosion failure, **Figure 5.2-15** to **Figure 5.2-18** show a leak repair on a 12-inch vintage steel main located in downtown Toronto. This steel main was installed in the 1960s, showing the use of mechanical fittings (compression couplings) to join gas mains together using a fabricated fitting (steel cross).

EGI continues to monitor the asset health of steel mains and updates its reliability models with best available information to determine the appropriate mitigating action. Work is ongoing to create a proactive vintage steel mains replacement program that uses the AHR program, reliability models, tacit knowledge and Operations input to identify vintage steel mains to be considered for replacement. Failure data from repair work orders and field observations made during steel main repairs and other maintenance activities show that vintage steel mains have demonstrated faster declining health compared to steel mains installed after the 1970s. This is attributed to material specifications, construction, past damage prevention practices and latent damage (such as coating damage) from third-party construction activities near the mains.

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Figure 5.2-15: Leak investigation on vintage NPS 12 gas main

Figure 5.2-16: Detail of fabricated fitting after removal

Figure 5.2-17: Multiple leaks due to severe corrosion on vintage NPS 12 gas main

Figure 5.2-18: Multiple leaks on vintage NPS 12 gas main

Figure 5.2-19 shows that for the EGD rate zone, about 70% of recorded steel main corrosion leaks in the past 11 years are from pipe installed before 1970. **Figure 5.2-19** also displays the failures normalized by pipe length, confirming that corrosion leaks per kilometre are disproportionately higher than those on post-1970 pipe. Similar behavior demonstrated on Union rate zone steel mains is noted through tacit knowledge–work is underway to formulate similar data analysis.

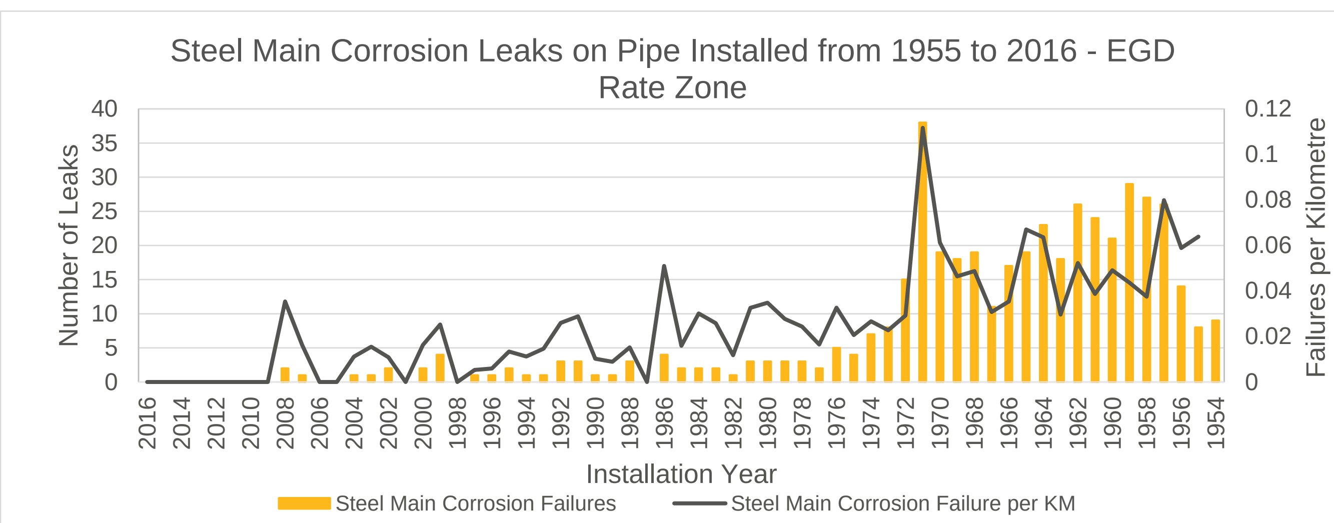

Figure 5.2-19: Steel Main Corrosion Leaks on Pipe Installed from 1955 to 2016 – EGD Rate Zone

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Using the steel mains reliability model, the AHR program evaluates the probability of corrosion leaks for the steel main population over the next 20 years. At a macro level and given the size of its population, steel mains as a group are generally performing well at their current age and over the next 10 years. It is important to note, however, that there are individual pipelines identified to be in poor condition and requiring mitigation, as illustrated in **Figure 5.2-15** to **Figure 5.2-18**.

Aside from analytics, tacit knowledge and condition assessments have identified condition and risk issues with some of EGI's more significant distribution mains. Damages to these mains could result in significant negative impact to public and worker safety and/or significant customer outages. Condition issues and risk concerns have been identified through tacit knowledge and condition assessments on the following mains:

NPS 20 Kipling Oshawa Loop (KOL) – Cherry to Bathurst

The NPS 20 Kipling Oshawa Loop (KOL) is a vintage steel main installed in 1954 and has segments located in densely populated areas in the City of Toronto along major traffic arteries, such as the Gardiner Expressway and Lake Shore Boulevard. The NPS 20 KOL pipeline has been the main feed to the City of Toronto since it was installed and is required to maintain the security of supply to existing customers and to manage the expected customer growth from proposed developments. Given the location of this high-pressure line, in the event of a gas leak, it could require shutting down a section of the Gardiner Expressway and Lake Shore Boulevard to ensure public safety as well as to facilitate the emergency repair.

ILI and integrity dig results on approximately 1900 metres of pipe (see **Figure 5.2-21** and **Figure 5.2-21**) between Cherry Street and Bathurst Street indicate significant corrosion. The NPS 20 KOL pipeline is known to have all the characteristics of vintage steel mains as discussed in **Table 5.2-3**, including but not limited to reduced depth of cover, shallow blow-off valves, drips/siphons, lack of cathodic protection, live stubs, stray current from hydro infrastructure and possible contaminated soil. A project has been initiated to replace this portion of inspected pipe from Cherry Street west to Bathurst Street and is scheduled to be in service for 2022.

Poor soil condition is considered one of the significant factors contributing to the degradation of the Cherry to Bathurst KOL segment. The soil is man-made fill containing large particulates in the form of large stone, brick, concrete and asphalt debris (see **Figure 5.2-22**). These large particulates can damage the protective coatings of the pipe wall and lead to corrosion initiation sites.

Figure 5.2-20: NPS 20 KOL pipeline displaying 70% wall loss identified by ILI in 2016

Figure 5.2-21: NPS 20 KOL shallow cover due to road grade changes

Figure 5.2-22: Soil conditions and particulates found – Cherry Street to Bathurst Street

NPS 20 Kipling Oshawa Loop (KOL) - Bathurst to Humber River

Based on the findings of poor soil and pipe condition between Cherry Street and Bathurst Street, EGI initiated a second project to investigate the next six-kilometre segment of the NPS 20 KOL main running west from Bathurst Street to Humber River. Specifically, if similar poor soil conditions continue westward, then poor pipe conditions may be present. Six integrity digs were performed for three kilometres of pipe immediately west of Bathurst Street that concluded the poor soil conditions in fact did continue west (see **Figure 5.2-23**) and that pipe condition may be degraded similar to the Cherry to Bathurst pipe segment. Further condition inspections are being explored to gain an increased understanding of the pipe condition and to determine if further mitigation is required.

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Figure 5.2-23 - Large particulates found within three kilometres immediately west of Bathurst Street

NPS 12 St. Laurent

The NPS 12 St Laurent main is a single-source system that consists of vintage steel mains installed in 1958 and is a critical supply to the cities of Ottawa and Gatineau, supplying natural gas to more than 165,000 customers. This pipeline feeds 12 distribution system stations and one header station, as well as numerous non-interruptible residential, industrial and commercial customers (including the Parliament buildings) and a natural gas-fired power plant.

The NPS 12 St. Laurent main is located in downtown Ottawa and is known to have all the characteristics of vintage steel pipe as discussed in **Table 5.2-3**. Should the NPS 12 St Laurent main experience a pipeline defect or sustain damage, EGI would have to either temporarily reduce operating pressures or shut down the line. Any pipe defects or failures that could release gas would require a significant emergency response and could have severe consequences. Shutting down the pipeline could lead to customer loss in excess of 60,000 on a cold day. **Figure 5.2-24** to **Figure 5.2-26** show areas in the St Laurent pipeline that exhibit poor condition.

Figure 5.2-24: Multiple corrosion sites on NPS 12 St. Laurent pipe

Figure 5.2-25: Gouges and dents due to latent damages

Figure 5.2-26: Coating damages

London Lines

The London Lines span approximately 83.5 kilometres and extend from Dawn to the Byron transmission station located in the London District. This major feed to the local municipalities and smaller towns consists of two single feed high pressure pipelines running in parallel. These pipelines were initially installed in 1935 and 1936 and although one was replaced in 1952, the replacement used reclaimed and refurbished materials with a vintage of 1920 to 1930. The London Lines account for a combined approximately 166 kilometres of some of the oldest pipe in the Union rate zone system.

The condition of the London Lines is generally poor, indicative of a pipeline reaching end-of-life, and is known to exhibit the characteristics of vintage steel pipe described in **Table 5.2-3**. A 2020 depth of cover survey reported that 47% of the London South main and 23% of the London Dominion line do not meet current minimum cover requirements. As well, 53 aerial crossings were identified.

Due to the condition of the London Lines, the current proposal is to complete a full replacement in one phase. A single-phase approach was based on condition, number of repaired and outstanding leaks and depth of cover issues. Project scope, costing and timing may change as additional pre-engineering is completed.

Figure 5.2-27 and **Figure 5.2-28** show areas in the London Lines that exhibit factors that can lead to poor condition and increase risk.

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Figure 5.2-27: **Aerial Crossing**

Figure 5.2-28: Exposed Ditch Crossing

Port Stanley Line

The NPS 8 Port Stanley line was constructed in 1959 and is approximately 20 kilometres in length. This single feed system provides natural gas to Port Stanley and St. Thomas, with about 13,000 customers, including the St. Thomas hospital, a psychiatric hospital in St. Thomas and a retirement home in Port Stanley. The pipeline has unknown grade and wall thickness, is classified as bare and unprotected and is known to exhibit the characteristics of vintage steel pipe described in **Table 5.2-3**.

The pipeline has had a number of leaks which have been compounded by maintainability issues. The pipeline is difficult to access in places and extensive corrosion has made welding repairs difficult to complete.

Figure 5.2-29 to **Figure 5.2-31** show areas in the Port Stanley line exhibiting factors that can lead to difficulty in maintaining the pipeline, poor condition and increased risk.

Further risk assessment work is required to establish the timing and need for this replacement.

Figure 5.2-29: Corrosion

Figure 5.2-30: Exposed Crossings

Figure 5.2-31: Below-grade Stations

Copper Services

Copper services were installed from 1960 to 1979 in the EGD rate zone only (**Figure 5.2-32**). Typical issues associated with these assets include leaks, circumferential cracks and choked flow due to build-up of corrosion by-product, resulting in the interruption of gas service. Degradation mechanisms for copper services include galvanic corrosion in the vicinity of the copper service connection to the main, external corrosion at above- and below-ground transitions and internal corrosion (also known as erosion corrosion), which causes thinning of the service wall over time.

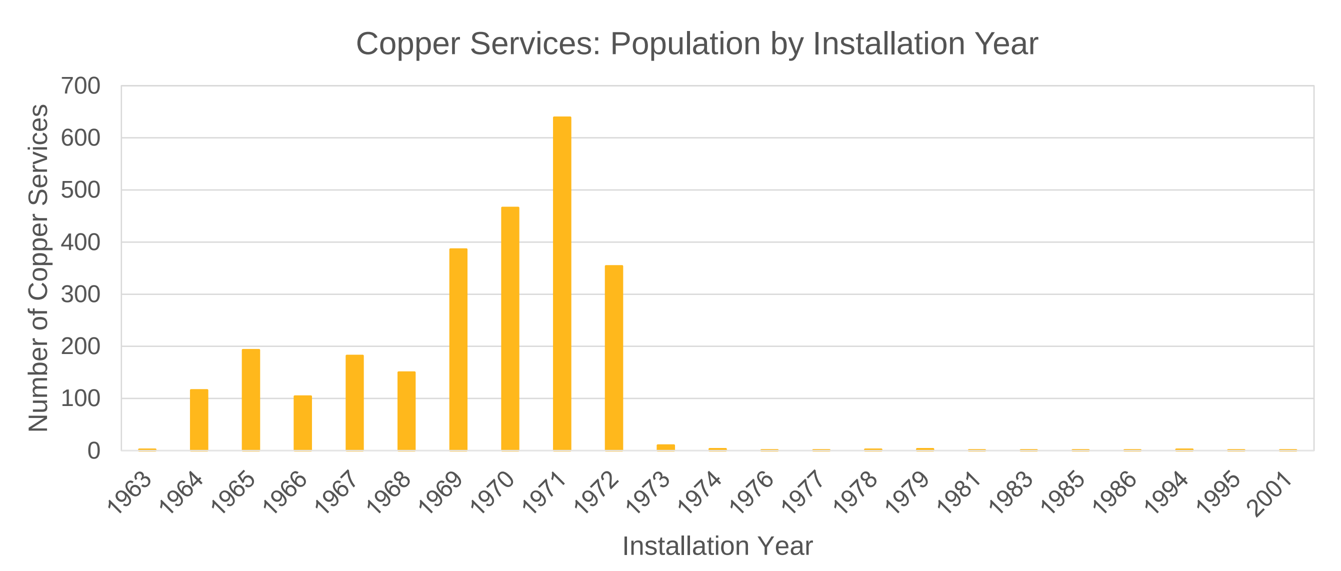

Figure 5.2-32: Copper Services: Population by Installation Year – EGD Rate Zone

Annual failure rates for copper services are steadily increasing (see **Figure 5.2-33**). Highest-risk copper services have been removed from the system and any remaining copper services now require replacement to prevent future failures.

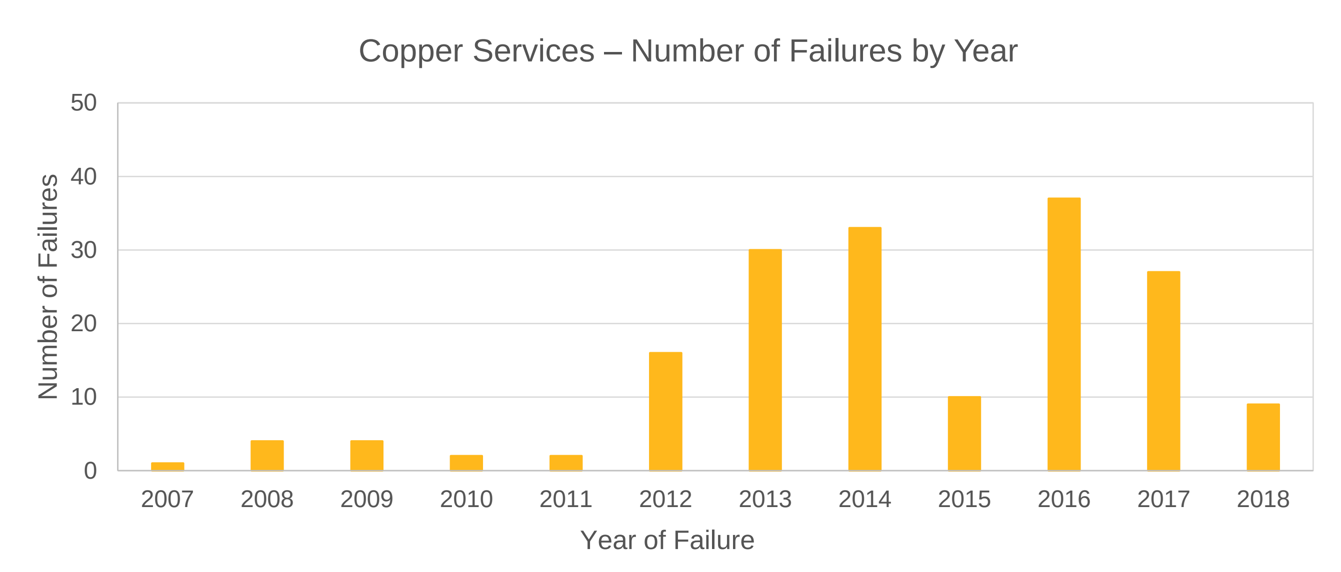

Figure 5.2-33: Copper Services – Number of Corrosion Leaks by Year

An additional failure mode is a choked service, where the internal corrosion debris from the copper pipe prevents the flow of natural gas to the customer. Loss of gas service during cold winter days for customers can cause reputational damage to EGI.

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5.2.6.1.3 Risk and Opportunity

Steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. Underground corrosion leaks can migrate to nearby structures and create gaseous environments. Leaks on steel mains in densely populated areas pose a greater risk than in suburban settings, as the ground surface is often paved across the entire width of the street, leaving no openings for escaping natural gas to vent to the atmosphere. In these cases, the path of least resistance can be underground infrastructure. Gas can migrate through these channels into buildings, creating a gaseous and potentially explosive environment for customers and the public. Corrosion leaks through pinholes are the common mode of failure for steel mains.

Health and safety risk (risks to the public, employees and contractors) represents the most aggressive risk increase over the next 40 years relative to other risk categories for steel mains. The increasing risk is driven by increasing corrosion leaks projected in the next 40 years. The current risk control strategy is not adequate to manage the accelerating risk in the next 40 years, requiring a proactive strategy to manage risk.

As illustrated in **Figure 5.2-14**, large portions of steel pipe in both rate zones are approaching the point where predicted poor condition will result in an exponential increase in leak rates. Based on reliability modelling, EGI expects that 1,300 and 1,800 kilometres of pre-1971 pipe for the EGD and Union rate zones respectively will reach this stage in less than 40 years. In order to proactively manage the anticipated increase in leaks, EGI is exploring programmatic and proactive replacement rates to manage risk, cost and performance. For example, a replacement rate of 155 kilometres per year is required to replace these 3,100 kilometres of pipe in 20 years. At the current rate of replacement (approximately 12 kilometres per year) it would take over 344 years to replace these 3,100 kilometres of pipe. Increasing the rate of replacement will likely be required to proactively manage the potential risk posed by the expected increase in leak rates.

Steel main repairs usually require more planning and resources than plastic main repairs. In many instances, specialized skill sets are needed to install isolation fittings on the steel mains and stop the flow of gas to facilitate the repair. This adds to the repair duration, causing longer service disruptions, more gas loss and higher repair costs. Additionally, with steel mains, if external corrosion exists near the leak location, welding may not be permissible for the repair work, adding additional cost and time for repairs.

By proactively replacing aging assets, savings can be achieved as planned work can be executed with less cost than emergency work once a leak has occurred. Furthermore, over 85% of the vintage steel network could be replaced with polyethylene (PE) pipe, eliminating cathodic protection and survey costs.

A proactive vintage steel replacement program will also level expenditures over time, an approach supported by EGI’s rate payers based on the 2020 Customer Engagement Survey results, which showed that distribution customers prefer EGI to maintain current reliability levels. Major projects that address main replacements in a single phase rather than multiple segments and disruptions were also supported. Both objectives can be achieved if assets reaching the end of their useful life are renewed through a proactive vintage steel program.

Copper service lines (underground gas infrastructure close to a building) pose another risk– a service leak may have a more direct path to the building foundation, increasing the chance of migration. Natural gas migrating into a building has the potential of creating a gaseous and potentially explosive environment, which poses safety and property risks.

The consequences of these failures are dependent on the proximity of the service to building premises, number of linear assets in the vicinity, foundation integrity and surface structures (soft/hard street surface). These consequences are then quantified and evaluated by translating the condition and leak projection to risk. This evaluation indicates that as the failure rate increases, so does cumulative asset risk. Other risks that are associated with pipe failures are relight costs, regulatory penalties, greenhouse gas (GHG) emissions and customer outages.

5.2.6.1.4 Strategy Outcomes

The approach for the Distribution Steel Pipe Pre-1971 asset subclass consists of program work that includes condition monitoring, a reactive repair program and proactive and reactive replacement programs.

The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing, including vintage steel and vintage plastic – both of which exhibit increased failures as they age. With 16,000 kilometres of vintage steel and 8,000 kilometres of vintage plastic, EGI is developing analyses to support maintenance and replacement strategies for these assets that balance risk, cost and performance.

EGI continues to evaluate load shed zones (system isolation) as a way to manage customer outages and improve safety and operational reliability, while balancing the opportunity for performance improvements with risk and cost.

The maintenance strategies are described in **Section 1.8.2** and the resultant replacement/renewal strategies for the Distribution Steel Pipe Pre-1971 asset subclass are as follows:

Corrosion Prevention Program

This program consists of annual anode replacements to ensure steel mains have adequate cathodic protection, using pipe-to-soil survey results to determine which steel main networks require additional or replacement anodes. In addition to active steel mains, the Corrosion Prevention program also covers corrosion control on steel casings and replacement of rectifier systems.

Emergency Replacement Program

This program addresses unforeseen pipeline emergencies that are small in nature. Examples of these types of jobs include cutting out a leaking section of main/fitting, removing blow-offs that require immediate attention, ongoing municipal work that encounters an unexpected gas plant–catch basin placements, structures, temporary main cut-out to access municipal plant, water mains, etc.

Service Replacement Program

A distribution service refers to the pipe between the distribution main and the customer’s meter set. Over the years, different materials have been used for this asset, including steel, copper and varying resins of plastic, each with unique characteristics that contribute to their performance over time. Services can be repaired or replaced depending on asset condition and the nature of the issue exhibited. Generally, replacement is the preferred approach to mitigate unacceptable asset condition.

Targeted Major Replacement Projects

Where the condition or risk related to a significant pipeline has been established to be a concern, EGI will establish a project team to gather relevant information, commission additional studies to support decision-making and evaluate alternatives to address the concerns. These pipelines may require a large capital investment subject to the OEB’s Leave to Construct (LTC) process. The approach to address larger pipe projects in one phase rather than multiple smaller projects is supported by EGI’s customers as reported in the 2020 Customer Engagement Survey, where residential customers preferred to replace old pipelines all at one time. A sample of larger pipelines where condition and risk are leading EGI to evaluate replacement is provided in **Section 5.2.6.1.2**. EGI always strives to maintain safe and reliable operations while delivering projects cost-effectively.

Distribution Steel Mains Replacement Program

A long-term program targeting higher-risk pipes is required to manage the increasing number of expected leaks. This planned and proactive replacement strategy recognizes that it is not cost-efficient to perform large numbers of steel main repairs on an emergency basis and that while emergency repairs improve the condition of small sections of the affected mains, the overall system is left in generally poor condition. Planned replacements eliminate all other active corrosion sites that have not failed yet and avoid the need for multiple leak repairs along the same steel system. Planned and proactive replacements will also control the expected number of leaks, allowing EGI to manage risk and maintain reliability and customer satisfaction. This proactive program will address steel mains in the following categories known to increase the likelihood of leaks:

- **Vintage steel mains**: Refers to steel mains installed in 1970 or earlier–these mains exhibit the condition problems described in **Table 5.2-3**. The proactive vintage steel mains replacement program selects vintage steel mains for replacement based on performance, analytics such as reliability model assessments, tacit knowledge and operational identification, integrity assessments and risk assessments.
- **Isolated steel headers**: Refers to steel gas mains on private property (such as shopping malls and condominiums) that supply more than one service. The common installation configuration is to connect a header station to a gas main to reduce gas pressure and supply gas to the header network. Steel headers are isolated from the cathodic protection of the upstream steel gas main network, allowing for accelerated corrosion rates.
- **Bridge crossings**: Refers to mains installed above-ground and affixed to a bridge structure. Mains on bridges are exposed to atmospheric elements and road salt during winter months, which could accelerate corrosion on the main, casing and pipe hangers. Annual bridge crossing surveys are conducted to identify faults and issues. Issues found trigger engineering assessments, which recommend risk mitigation measures, such as the replacement of components or the entire bridge crossing if necessary.
- **Exposed mains or insufficient depth of cover**: Refers to steel mains found to have insufficient depth of cover. Municipal roadwork and city development can alter the road grade and cause gas mains to be shallower than the original installed depth. (See **Table 5.2-3** for more details.) To the extent possible, depth of cover issues will be addressed by localized mitigation. If localized mitigation is not feasible, it will be mitigated by main replacement.
- **Leaking steel mains and emergency replacements**: Throughout the year, unforeseen short main replacement projects must be expedited on short notice, such as replacing a short section of main or fittings that are leaking, removing blow-off assemblies or repairing mechanical fittings that require immediate attention.

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Bare and Unprotected Steel Pipe Replacement Program

This program manages the replacement of all bare and unprotected steel mains in the Union rate zones. These mains are more susceptible to leaks as they have not been cathodically protected since installation. About 60% of these mains are in urban areas, approximately 5% of which are in highly-developed areas. The remainder are in rural areas. Removing these mains from service will reduce the potential for leaks due to corrosion. Some examples of bare and unprotected failures are shown in **Figure 5.2-34**. This program was part of the 2020 Customer Survey, where preferences were mixed among Union rate zone customers. More than half of residential customers would prefer that the replacement of bare and unprotected pipes be prioritized, whereas less than half of the contract and non-contract business customers would prefer the work to be prioritized.

Figure 5.2-34: Bare and unprotected steel failures

Continuous improvement of reliability models

The Distribution Steel Mains Replacement Program is paced based on projected leak rates over the next 10 years. As shown in the corrosion leak projections (**Figure 5.2-13** and **Figure 5.2-14**), at the current replacement rate, the risk will continue to increase. In the Asset Health Review program, the steel main reliability model points to an average time to first failure at approximately 100 years, where the barriers of coatings and cathodic protection break down. It is expected that based on increasing leak projections, the long-term challenge for EGI will be to manage leak acceleration in the steel main system. As stated in **Section 5.2.6**, vintage steel mains account for more than 50% of the steel pipe population.

EGI will continue to refine the program to manage this aging asset population based on advancements in the understanding of leak projections, asset age limit and resource capacity. Considerations include:

- Monitoring leak rates and improving data collection to further validate and improve steel main reliability and risk models
- Increasing understanding of other degradation factors that affect asset life such as weldability for repairs
- Evaluating potential logistics and resource constraints based on reliability modelling and current leak projections

Relocation Program

A relocation project is required when a municipality, road authority, outside agency, other utility or other third party constructs or reconstructs a road, bridge, railway, canal, building, etc. and the work is deemed in conflict with an existing gas plant.

This program aims to relocate gas-carrying assets in conflict with third-party proposed work, ensuring conflicts are resolved within the framework of various third-party agreements (in most cases by relocating the existing gas infrastructure) to ensure the continued safe and reliable delivery of natural gas to customers. Relocation renews the asset by replacing it with new pipe.

Copper Services Replacement Program

The proactive Copper Services Replacement program aims to remove all outstanding active copper services and replace these assets with new plastic services and anodeless risers as part of the Service Relay program. Additionally, EGI will be monitoring condition-based and customer-related drivers that trigger the need to replace these assets. Condition-based drivers are monitored through existing activities of the DIMP, as well as the Leak and Corrosion Survey programs. Copper services are also replaced through proactive vintage mains replacement programs and relocation projects.

5.2.6.2. Distribution Steel Pipe Post-1970

The Distribution Steel Pipe Post-1970 asset subclass consists of mains (along with associated services and components) installed after 1970 and covered by the Distribution Integrity Management Program (DIMP). In this portfolio, the steel pipeline system consists of approximately 14,500 kilometres of steel mains for EGI (see **Figure 5.2-4** and **Figure 5.2-5**). This pipe was generally constructed with improved materials and construction practices and is performing well. These mains operate at different pressure classes, ranging from low pressure to extra-high pressure.

Although post-1970 steel mains are exposed to many of the same hazards as steel mains from 1970 and earlier, their materials, coatings and construction practices have enabled the primary corrosion barriers of pipe coating and cathodic protection to be more effective, resulting in fewer corrosion-based leaks.

5.2.6.2.1 Condition Methodology

See **Section 5.2.6.1.1**.

5.2.6.2.2 Condition Findings

The condition methodology for distribution steel pipe is described in **Section 5.2.6.1**. These mains are exposed to some of the same issues as steel mains from 1970 and earlier (see **Table 5.2-3**). However, some issues (such as unrestrained compression couplings) do not apply due to different design and construction practices and other issues (such as corrosion) are better mitigated as a result of better construction practices, maintenance practices and materials. Corrosion-based leak history for the post-1970 distribution steel main population for the EGD and Union rate zones is shown in **Figure 5.2-35** and **Figure 5.2-35** respectively.

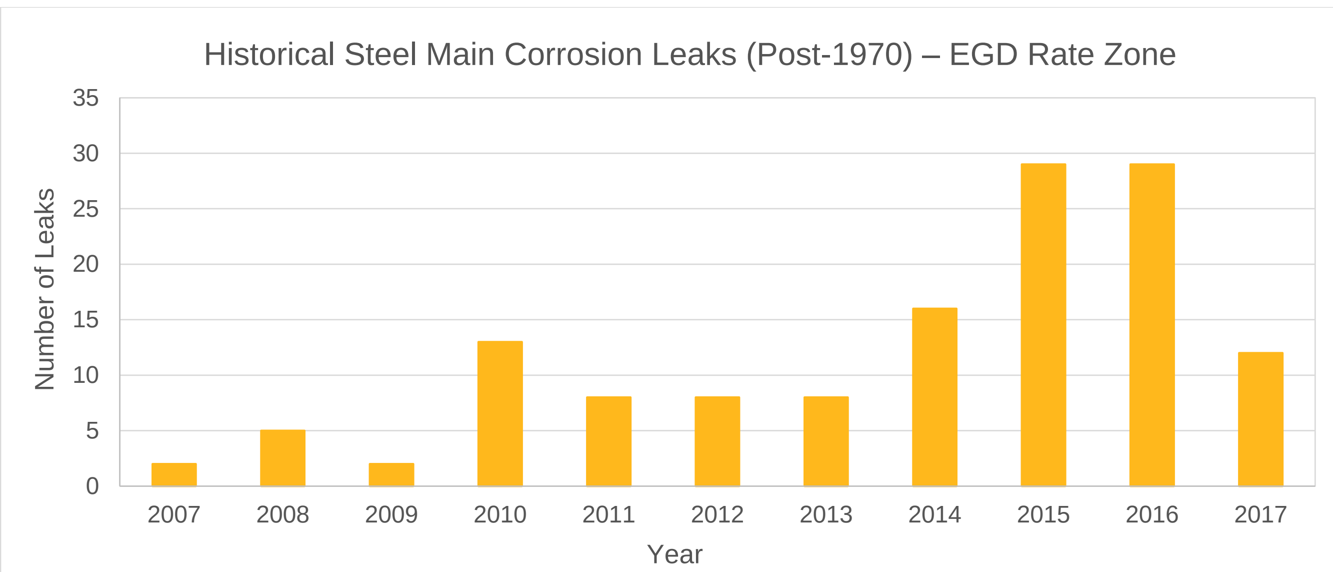

Figure 5.2-35: Historical Steel Main Corrosion Leaks (Post-1970) – EGD Rate Zone

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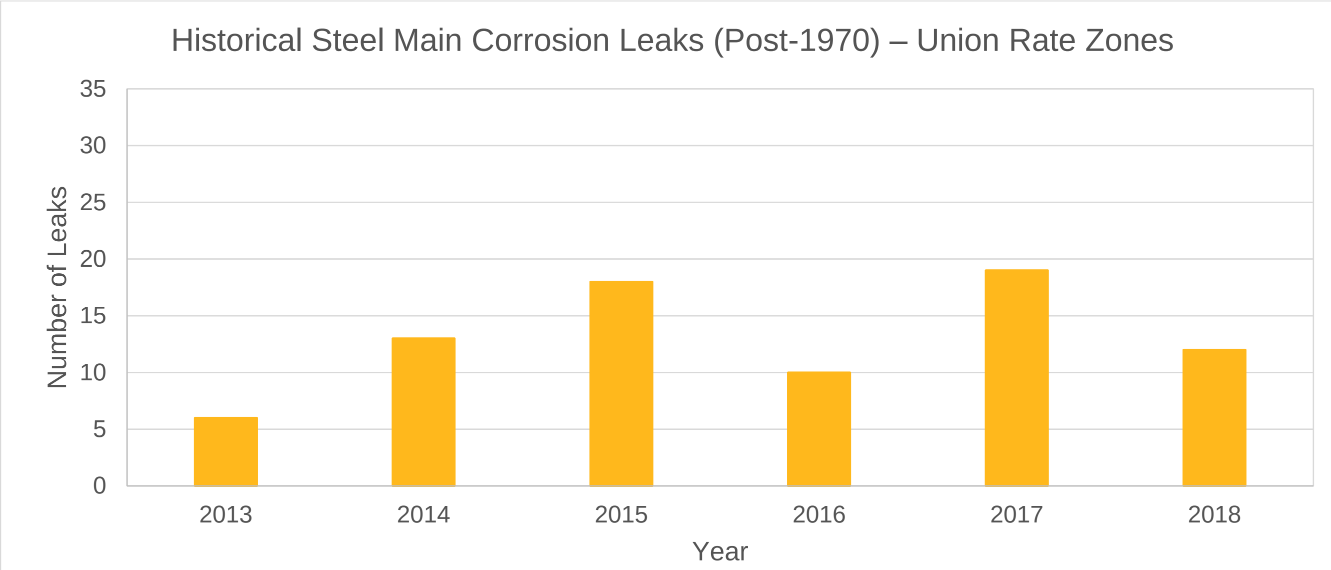

Figure 5.2-36: Historical Steel Main Corrosion Leaks (Post-1970) – Union Rate Zones

5.2.6.2.3 Risk and Opportunity

As demonstrated by the forecasted leak trends (see **Figure 5.2-37**), the post-1970 steel mains population is performing well and is expected to continue to perform well in future years, with leak rates that do not pose a significant risk. Mains are in good condition, associated with adequate cathodic protection and good coating performance. However, some hazards (third-party latent damages, environmental conditions, etc.) may accelerate degradation and result in leaks. These carry the same risks noted for pre-1971 distribution steel mains (see **Section 5.2.6.1**), including supply interruption to customers and greenhouse gas emissions associated with an uncontrolled gas release. As well, gas can migrate into buildings, creating a gaseous and potentially explosive environment for customers and the public.

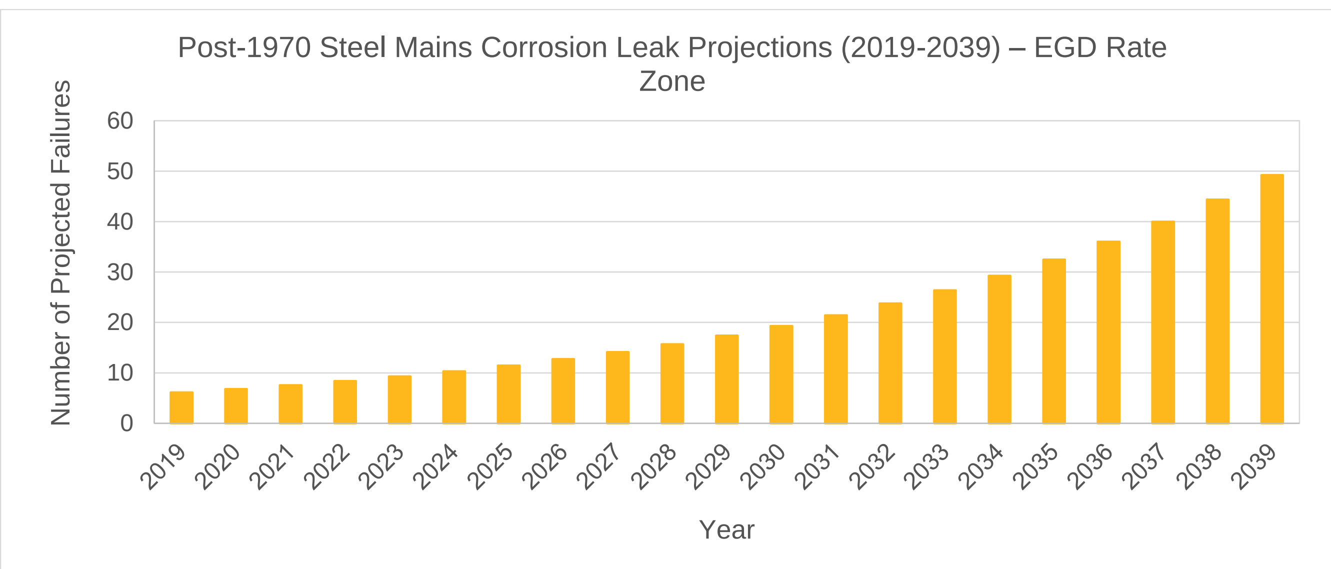

Figure 5.2-37: Post-1970 Steel Mains Corrosion Leak Projections (2019-2039) – EGD Rate Zone

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5.2.6.2.4 Strategy Outcomes

The maintenance strategy for post-1970 distribution steel pipe is consistent with pre-1971 distribution steel pipe (see **Section 5.2.6.1**), where several condition inspection programs are in place, such as the Leak Survey and the Cathodic Protection Survey programs. The preferred life cycle approach to corrosion leaks on post-1970 distribution steel pipe is to repair them as they are discovered and perform replacements for a few select mains where condition, risk and other factors cause a repair to be not viable through the Distribution Steel Mains Replacement program. The number of failures for this asset subclass in the short term is considered manageable through existing approaches. EGI continues to monitor these failures to determine if a proactive maintenance and replacement program is required. This strategy meets the expectations of EGI's rate payers for sustaining a reliable system, based on the 2020 Customer Engagement Survey where 53% of respondents indicated that maintaining current reliability levels was a priority.

5.2.7 Distribution Plastic Pipe

Plastic mains were first introduced into EGI's distribution network in late 1960s on a field trial basis. Plastic mains became more widely used in the early 1970s and have since been installed across the EGI franchise area, replacing steel mains in low and intermediate pressure class systems. Plastic mains assets are divided into three subclasses: Vintage Plastic Aldyl A, Distribution Plastic Pipe Early Resins and Modern Polyethylene (PE) Resins. In some instances, records are not clear on pipe material-conservative assumptions were made to categorize the asset. In the Union rate zones, work is required to classify some pipe assets, currently grouped as To Be Categorized Plastic.

Population distributions for the EGD and Union rate zones are shown in **Figure 5.2-38** and **Figure 5.2-39** respectively.

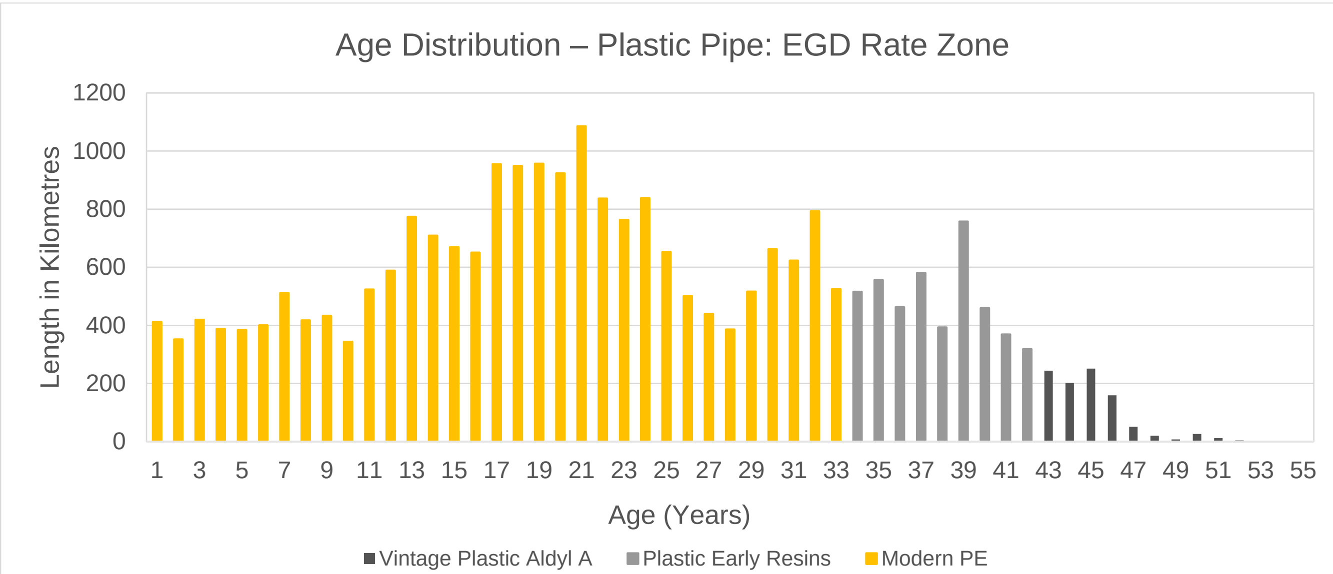

Figure 5.2-38: Age Distribution – Plastic Pipe: EGD Rate Zone

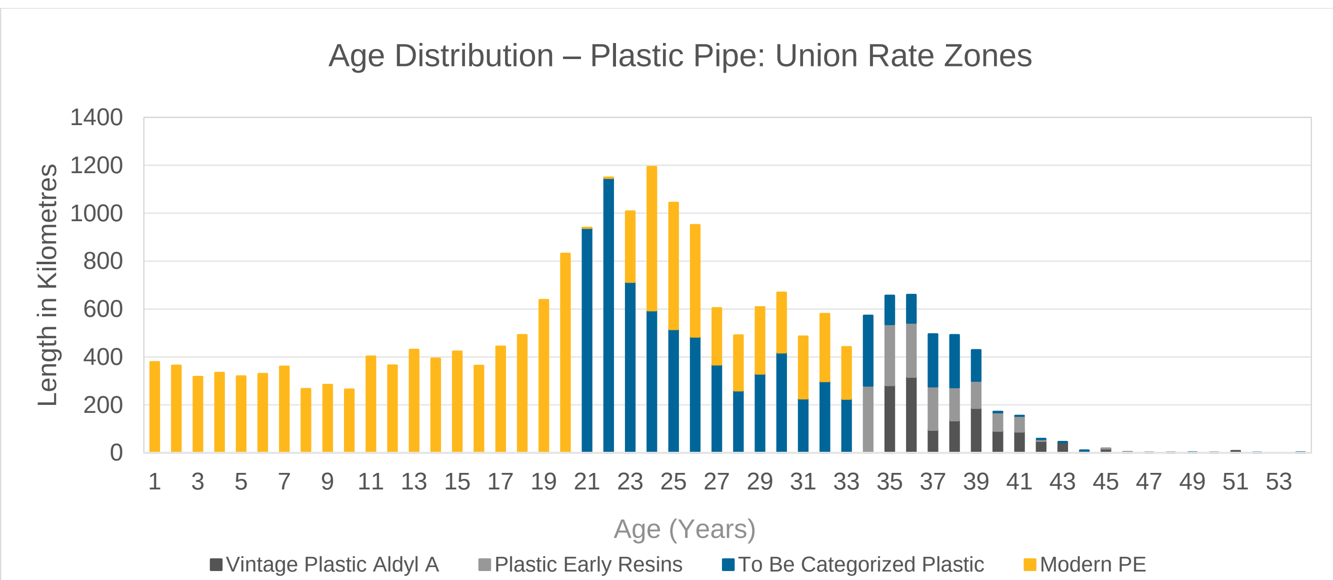

Figure 5.2-39: Age Distribution – Plastic Pipe: Union Rate Zones

Copper risers are also discussed in this section as they are primarily associated with vintage plastic Aldyl A and early resins systems. Copper risers on these systems include an AMP-fitting (a mechanical transition fitting between the plastic service

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and the copper riser). These assets were installed between 1969 and 1984 in the EGD rate zone only. **Figure 5.2-40** illustrates the calendar age of the copper riser population for the EGD rate zone as of 2019.

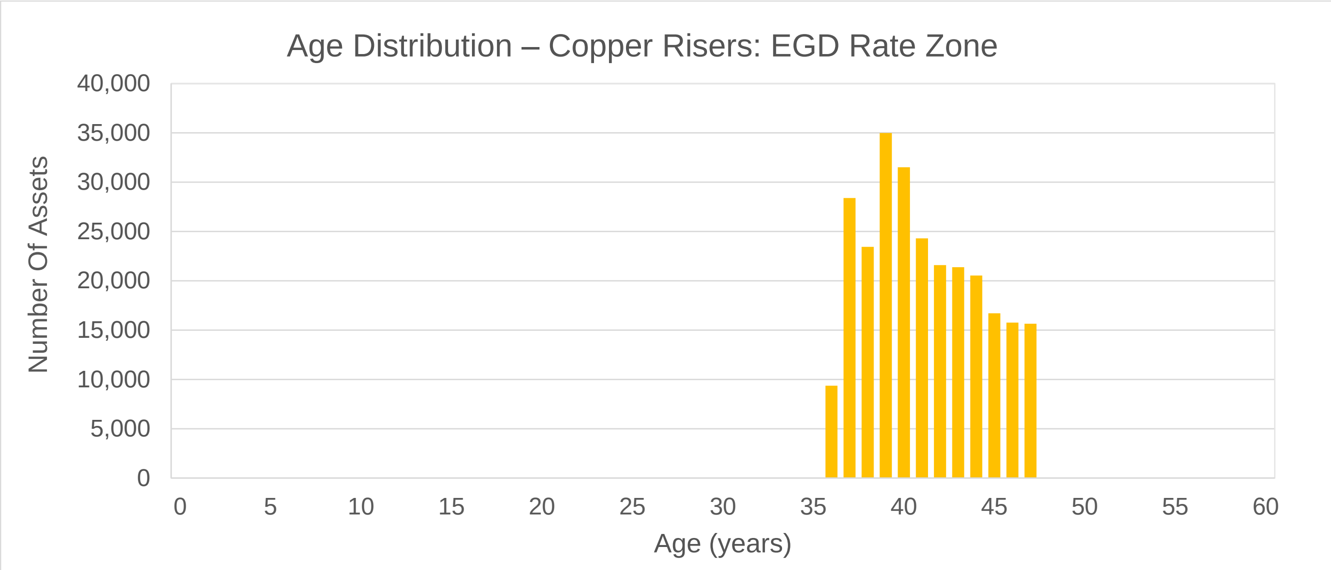

Figure 5.2-40: Age Distribution – Copper Risers: EGD Rate Zone

Note: Condition Methodology and **Risk and Opportunity** are consistent across plastic pipe assets. Asset subclasses are discussed in detail in Condition Findings only.

5.2.7.1. Condition Methodology

The condition methodology of distribution plastic mains is common across its asset subclasses. The condition of these assets is determined through:

- **Maintenance programs**: These programs (such as leak surveys) monitor asset conditions and restore assets to their functional state. Failure data from leak surveys is used to manage leaks in the short term and to build reliability models for pipe and copper services in the longer term.
- **Condition assessment programs**: These programs (such as integrity assessments and material fault reporting) identify and assess the failure mechanisms of EGI's assets. EGI has also concluded an extensive study on vintage plastic Aldyl A pipe with Gas Technology Institute (GTI) to develop data-driven predictions on the remaining useful life expectancy of plastic pipe. Studies are now being extended to Early Resins material to further enhance EGI's knowledge of this material; sampling programs and laboratory testing for TR-418 are underway with results analysis expected by 2022.
- **Tacit knowledge (SMA/Worker input)**: Field knowledge is used to identify potential condition issues through regular meetings with subject matter advisors (SMAs).
- **Reliability modelling**: A reliability model has been developed for vintage plastic Aldyl A pipe and copper risers through the Asset Health Review (AHR) program under the Distribution Integrity Management Program (DIMP). This has used a structured methodology to convert historical failure data into a statistical model that forecasts the probability of failure. Leak projections are refined with input obtained through direct assessment, internal and external industry studies and SMA input.

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5.2.7.2. Condition Findings

The methodologies described in **Section 5.2.7.1** drive condition findings for the following subclasses: Vintage Plastic Aldyl A, Vintage Plastic Early Resins, Copper Risers and Modern PE Resins.

Vintage Plastic Aldyl A

Vintage plastic Aldyl A mains are the earliest plastic mains used within the distribution system; the installation period of Aldyl A plastics started in the late 1960s on a field trial basis and was concluded by the end of 1976 for the EGD rate zone and 1984 for the Union rate zones.

It is well known and studied in the North American gas industry that Aldyl A plastic mains have brittle-like cracking properties. The oxidation of the inner wall surface during manufacturing (also known as Low Ductile Inner Wall (LDIW)) and the large spherulites found in its microstructure causes pipe to be susceptible to cracking and premature failure in the presence of stress intensifiers such as a large number of connections, squeeze-off locations and the presence of rock impingement points caused by rocky soil types.

Many gas utilities have already started and in some cases completed, the replacement of Aldyl A pipe as a result of concerns about its brittle-like cracking properties. EGI commissioned a study through GTI to evaluate the performance of varying vintages of Aldyl A pipe used by EGI to identify failure modes over time and to determine the mean time for failure. Results of the initial sample testing showed that the LDIW property was observed and that the expected asset life of Aldyl A plastic mains is highly affected by ambient temperature and total stress intensifiers on the pipe.

Figure 5.2-41: Rapid crack propagation on Aldyl A pipe from saddle tee fusion (Mississauga, ON)

Using the failure data and statistical modelling yields a reliability model that shows a very strong correlation to asset age, although it is important to note that the model is based on a relatively small number of failures. The reliability model for vintage Aldyl A plastic mains shows a sharp increase in failure rate by age 70. Leak projections based on historic failure rates for the asset subclass are shown in **Figure 5.2-42**. At this time, factors which lead to stress intensification such as rock impingement, number of connections and squeeze-offs have not been considered in this model.

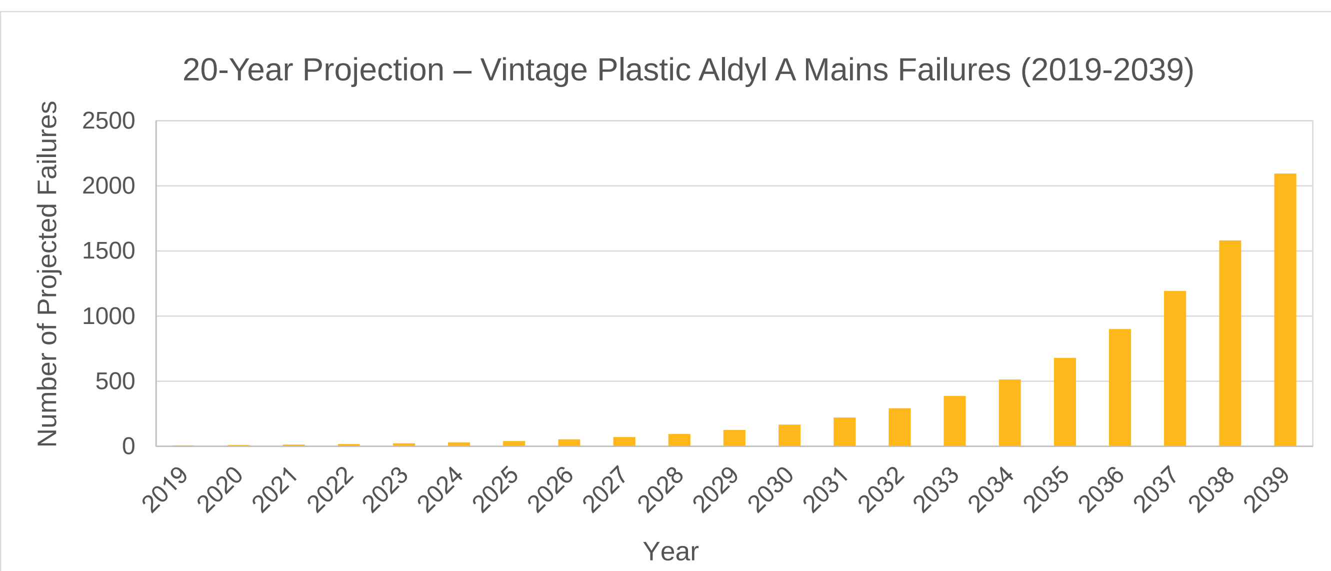

Figure 5.2-42: 20-Year Projection – Vintage Plastic Aldyl A Mains Failures (2019-2039)

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The current population of vintage plastic Aldyl A mains is in generally good condition; however, it is important to note that the entire population is aging and will degrade quickly (see **Figure 5.2-43**). The sudden change in performance can be attributed to the LDIW property and slow crack growth (SCG) behavior, as the mains operate with additional stress intensifiers over a long period of time. This combination of material property and operating environment results in the brittle-like cracking of Aldyl A plastic mains (i.e., rapid crack propagation), a finding supported by the GTI study on Aldyl A samples supplied by EGI. The study indicated that by combining different stress factors, the asset life for vintage plastic Aldyl A mains is in the 70-year range. This implies that the residual asset life of pre-1977 plastic mains could be as short as 10 to 20 years.

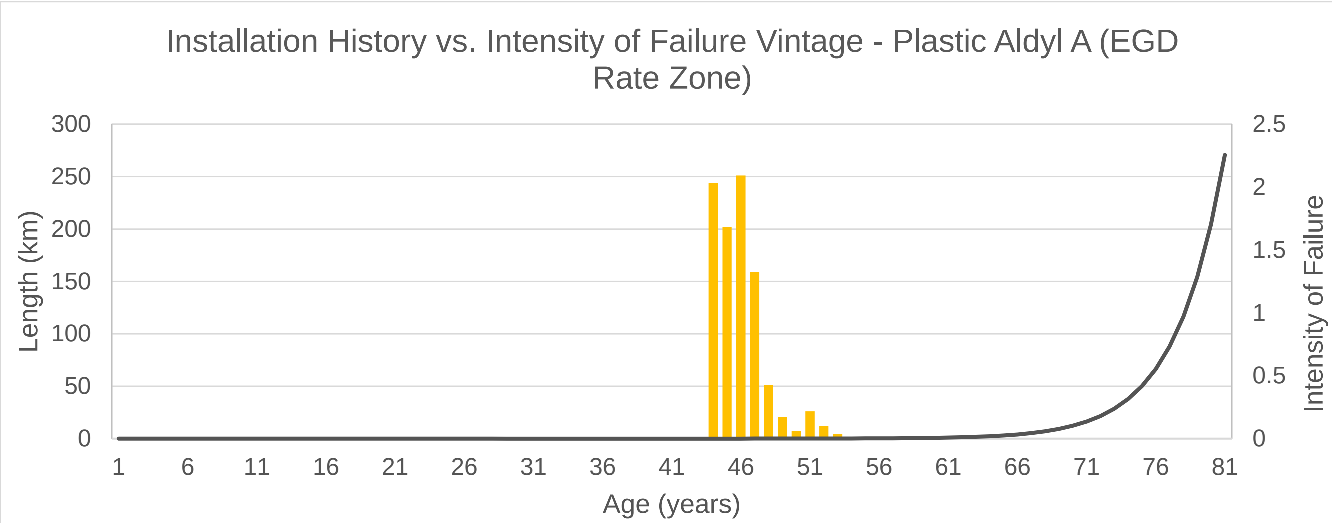

Figure 5.2-43: Installation History vs. Intensity of Failure - Vintage Plastic Aldyl A (EGD Rate Zone)

Plastic Pipe Early Resins

After using vintage plastic Aldyl A pipe, EGI transitioned to installing other resin-based plastic pipes designated as Early Resins, such as Aldyl HD and TR-418. This occurred by the end of 1976 and by 1977 for the EGD and Union rate zones respectively, with an overlap period of vintage plastic Aldyl A installations as early resins pipe was introduced.

Early resins pipe was phased out by 1985 in the EGD rate zone. For the Union rate zones, there remains a population of plastic pipe not readily classified (designated as To Be Categorized Plastic) and may include some vintage plastic Aldyl A and early resin material. The installation year for this population extends until 1998. Excluding pipe designated as To Be Categorized Plastic, the current asset age of early resins pipe ranges from 32 to 40 years and 34 to 42 years for the EGD and Union rate zones respectively.

From statistical analysis on failure data, it is predicted that early resin and vintage plastic Aldyl A mains will have very similar leak projection trends, leading to the conclusion that the asset health of early resins plastic mains will resemble the general trend of vintage plastic Aldyl A mains, but with a delay in degradation due to the later installation date. Much like the vintage plastic Aldyl A mains, this group is currently in good condition and will continue to perform over the next 20 years (**Figure 5.2-44**).The population will then start to degrade and because of its size, will result in higher leak rates (**Figure 5.2-45**).

In addition to reliability models and leak projections, multiple cases of early resins plastic main failures exhibiting similar failure modes (cracking due to extended stress exposure) as the vintage plastic Aldyl A mains were identified. Currently, there is no known industry research or investigation completed on early resin plastic mains to provide insight to its degradation and failure mechanisms. Sampling programs took place in 2019 and 2020 to extract samples from EGI pipe systems to further enhance EGI knowledge. More investigation into the failure data and research on this specific plastic pipe group is required to fully understand this modelling result (further discussed in **Section 5.2.7.3**).

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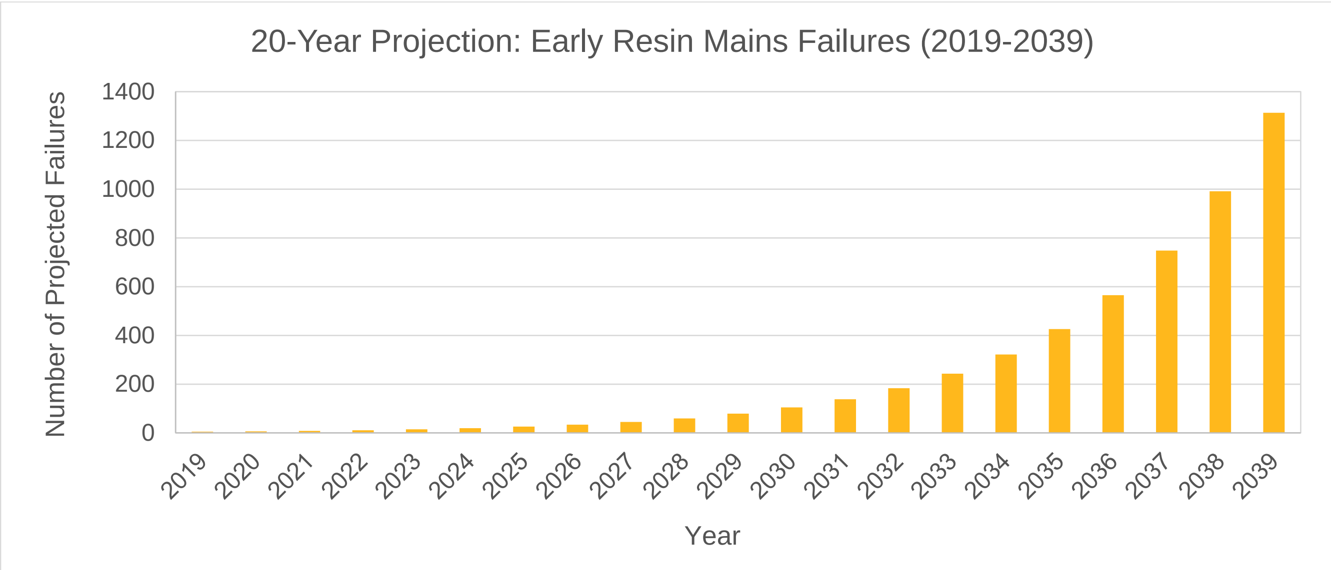

Figure 5.2-44: 20-Year Projection – Early Resin Mains Failures (2019-2039)

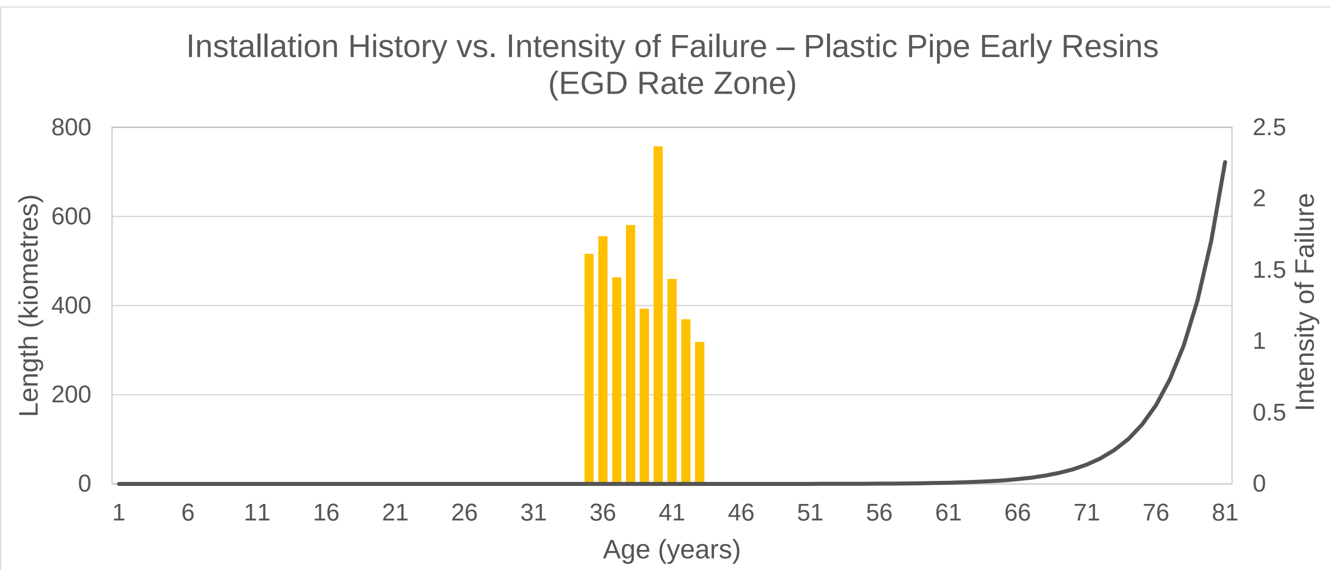

Figure 5.2-45: Installation History vs. Intensity of Failure – Plastic Pipe Early Resins (EGD Rate Zone)

Copper Risers

The copper riser's AMP-fitting causes a disturbance in the flow of gas, creating a low-pressure zone after the fitting when the gas flow becomes turbulent. This turbulence causes an erosion-corrosion failure to occur, which manifests itself into a pinhole or a circumferential crack. All sampled copper risers have shown some degree of corrosion after the AMP-fitting. Based on the sampled risers and reliability modelling, it is expected that all copper risers will corrode, causing a leak at some point in their lifetime. Subsequent sampling has confirmed these findings. The reliability modelling for copper risers has been refined to improve failure forecasts.

The predominant failure mechanism for these assets at EGI is associated with turbulent flow and is not affected by external conditions or the environment. Analysis determined the conditions (pressure and flow) that would lead to this and supported the sampling program which showed wall loss on all copper risers. The AMP-fitting assembly, typical AMP-fitting installation and localized corrosion failure are illustrated in **Figure 5.2-46**, **Figure 5.2-47** and **Figure 5.2-48**.

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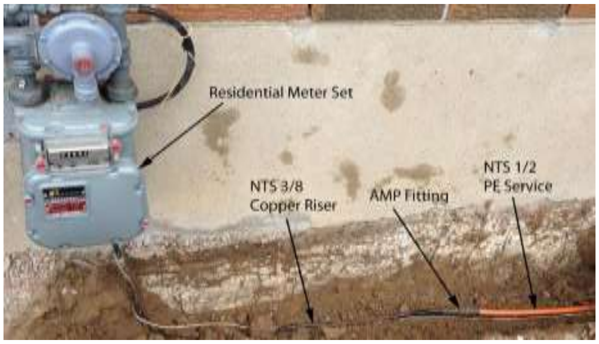

Figure 5.2-46: AMP Fitting Assembly

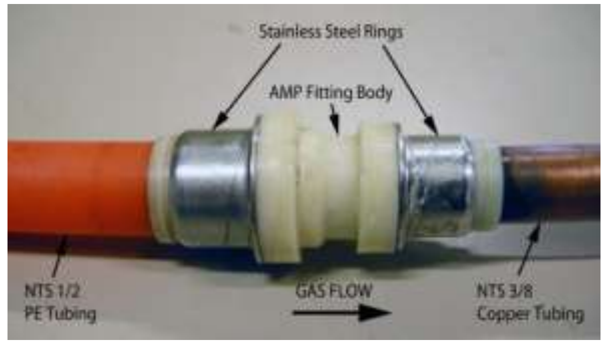

Figure 5.2-47: Typical AMP Fitting Installation

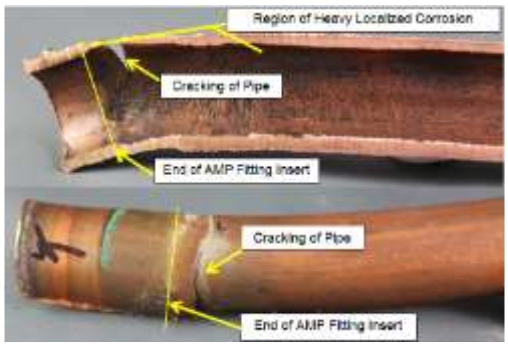

Figure 5.2-48: Localized Corrosion Failure at AMP Fitting Outlet

The condition of copper risers is expected to significantly degrade over time with a yearly increase in the number of leaks over the next 10 years as shown in a cumulative distribution function in **Figure 5.2-49.** Actual failure data has trended very closely to the statistically projected number of leaks as shown in **Figure 5.2-50**.

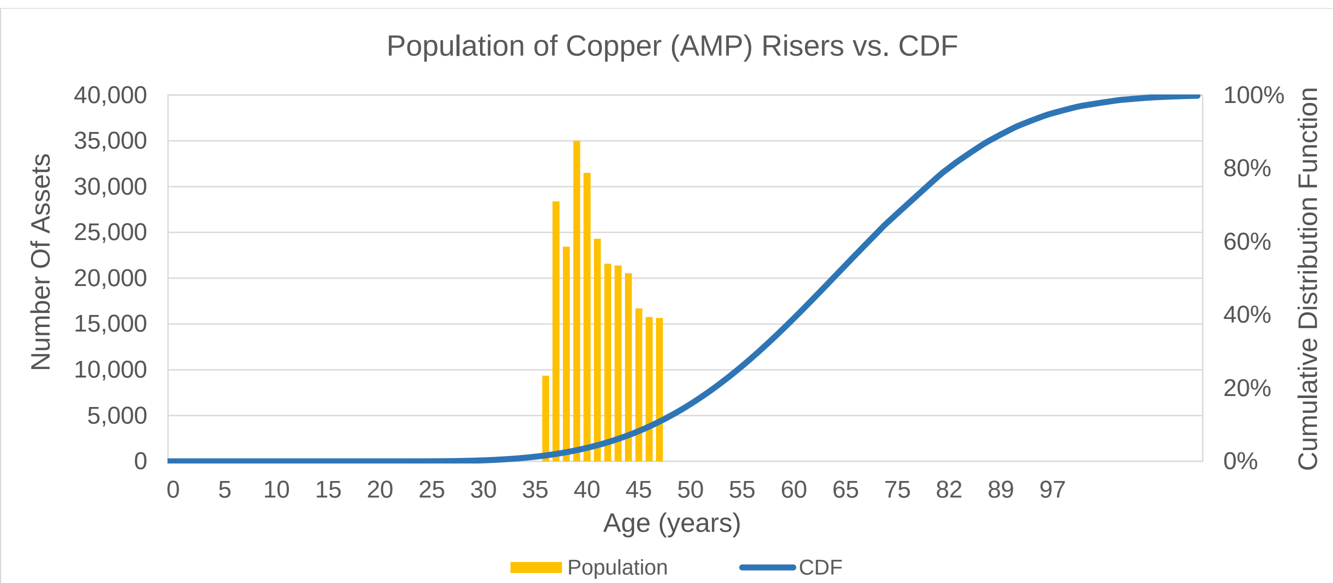

Figure 5.2-49: Population of Copper (AMP) Risers vs. CDF: EGD Rate Zone

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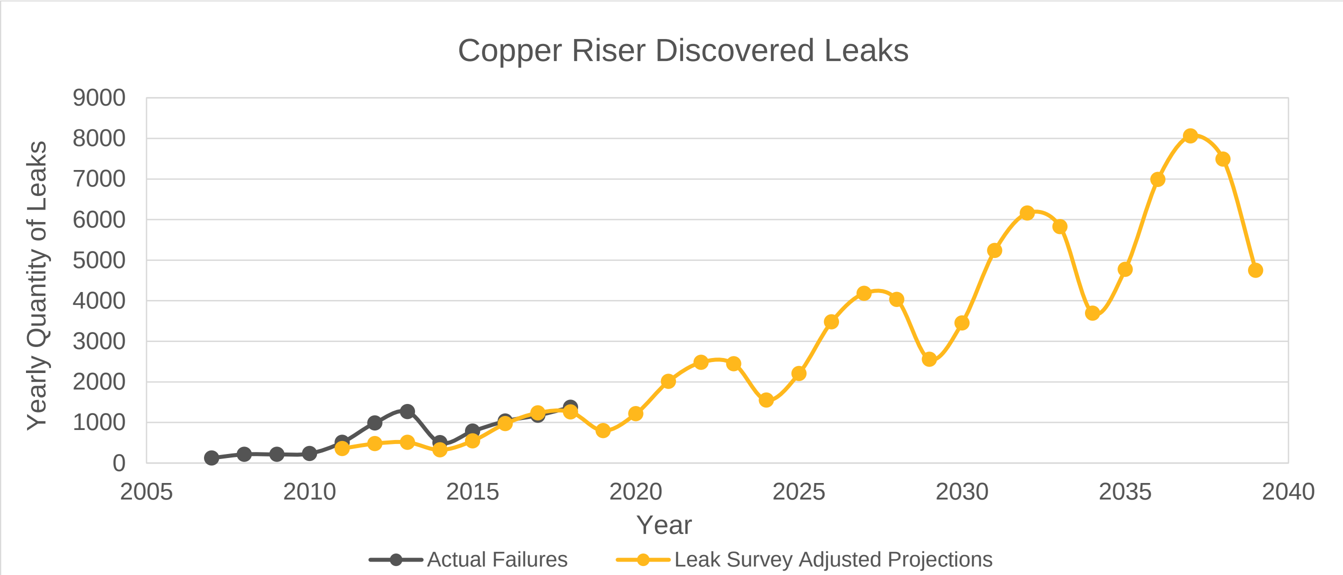

Figure 5.2-50: Copper Riser Discovered Leaks

Modern PE Resins

By the mid-1980s, EGI had started to use a different resin type, classified as Modern Polyethylene (PE) Resins. The newer generation of plastic resin and the improvement of installation practices resulted in a plastic mains asset that outperformed earlier assets of its kind. These newer resins have experienced fewer failures. EGI continues to gather data to better understand failure modes and mean time to failure.

The industry has proven that these resins do not exhibit slow crack growth (SCG) issues. These are relatively young assets and have experienced few material failures, and as such, statistical analysis to project future failures has been difficult. The entire population of this asset subclass is expected to remain in good condition for at least the next 40 years. A failure projection model is not included for this asset subclass.

5.2.7.3. Risk and Opportunity

The risks identified for distribution plastic mains apply to the entire Distribution Plastic Pipe asset subclass:

- **Safety Risk**: Gas leaks and migration through underground conduit into buildings can result in gas accumulation and explosions.
- **Financial Risk**: Total repair costs, commodity loss, relighting customer gas appliances, regulatory penalties and any property damages caused by a gas leak
- **Operational Risk**: GHG emissions, environmental impact, service interruptions and reputational damages
- **Environmental Risk**: Greenhouse gas (GHG) emissions, environmental impact

For vintage plastic Aldyl A mains, slow crack growth (SCG) issues can lead to a steep failure curve, illustrating that the asset performs over time until sudden cracking occurs, accelerating the failure rate in a short period of time. This presents an opportunity to reduce failures by implementing a replacement strategy to manage the risk related to this asset subclass as a whole.

The brittle-like cracking observed on plastic mains creates a large opening on the pipe and releases a high volume of uncontrolled gas underground. If there is no way to vent to the atmosphere, gas can travel through any nearby underground infrastructure and migrate into buildings to create a potentially explosive environment. At a high volume flow rate, this accumulation could occur in a short period of time.

Copper risers have the potential for a circumferential leak and by their nature they are near building foundations. This leaves the opportunity for the gas to leak and migrate into buildings, accumulate and create a potentially explosive environment.

As the number of leaks grows over time, there is a risk to EGI's ability to respond to emergency calls and manage operational costs.

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5.2.7.4. Strategy Outcomes

EGI evaluates asset strategies for the value that they deliver in terms of operational reliability, risk and cost over the long term. This drives a combination of reactive programs to respond to assets that have already failed and proactive programs to manage the growing number of leaks expected to occur as pipe assets approach the end of their useful life and the overall system condition degrades.

Maintenance strategies are described in **Section 5.2.4** and lead to the following replacement/renewal strategies for distribution plastic pipe:

Vintage Plastic Aldyl A Replacement Program

For this asset subclass, sufficient industry data and EGI internal failure history support the need for a replacement program. Early resins plastic mains will need to be further studied and understood through similar sampling and testing to justify a systematic asset renewal program. EGI continues to monitor all plastic mains through a leak survey program on regular cycles; leaks and other material faults with vintage plastic Aldyl A mains are addressed on a reactive basis.

The asset life of vintage plastic Aldyl A mains is estimated to be approximately 70 years. To maintain this average asset age, approximately 900 kilometres of vintage plastic mains will require replacement over the next 25 to 30 years, at an average replacement rate of 40 kilometres per year.

To identify an optimal replacement pace, an analysis was performed to identify the residual leak rate associated with different replacement rates over a 40-year period as shown in **Figure 5.2-51**.

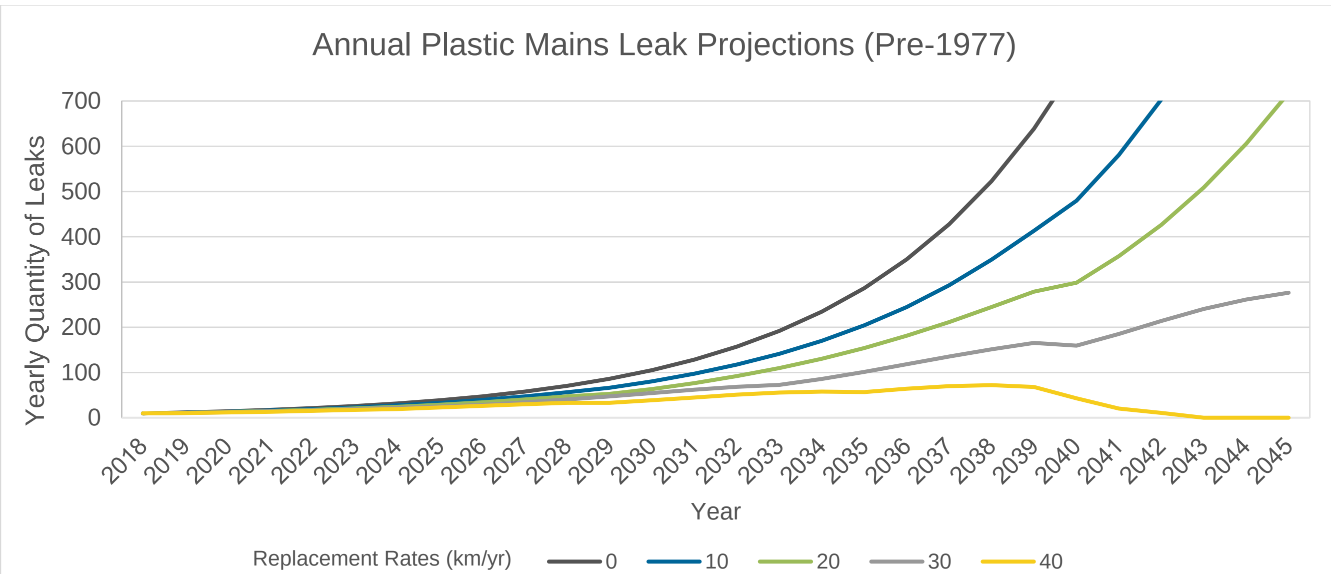

Figure 5.2-51: Annual Plastic Mains Leak Projections (Pre-1977)

Figure 5.2-51 shows the current reactive replacement approach (i.e., no proactive replacement) will result in significant increase in plastic main leaks over the next 20 years.

Because of rapid deterioration, the strategy is to increase the replacement rate to 20 kilometres per year for pre-1977 plastic mains in the next 10 years, with an immediate focus on replacing plastic mains that have experienced SCG failures due to known stress intensifiers (such as rocky soil type) and replacing early vintage field trial plastic mains pre-dating the implementation of plastic mains in the early 1970s. EGI will continue to monitor asset conditions to evaluate the asset life of pre-1977 plastic mains and determine the long-term replacement pace required to maintain the average asset age below the estimated asset life. This strategy ensures the risk is managed over the long term and replacement programs can be adequately resourced. In the short term, failing assets will be repaired or replaced as required. EGI continues to monitor asset conditions to determine if a change in pace is needed.

Emergency Replacement Program

See **Section 5.2.6.1.4**.

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Service Replacement Program

See **Section 5.2.6.1.4**.

Relocation Program

See **Section 5.2.6.1.4**

AMP-fitting Replacement Program (Copper Risers)

Based on the Asset Health Review program and reliability models, it is expected that the majority of copper risers will fail after 2037. The degradation of the asset is significant, outpacing current leak quantities over the next 10 years. Due to the very large numbers of projected leaks, a replacement program is required to manage the risk and ensure that costs and emergency response can be managed on a year-by-year basis. The current pacing of the replacement program plans to replace increasing numbers of copper risers per year starting at 4,000 units in 2020 and increasing to 20,000 by 2026. **Figure 5.2-52** demonstrates the number of expected leaks discovered on a yearly basis.

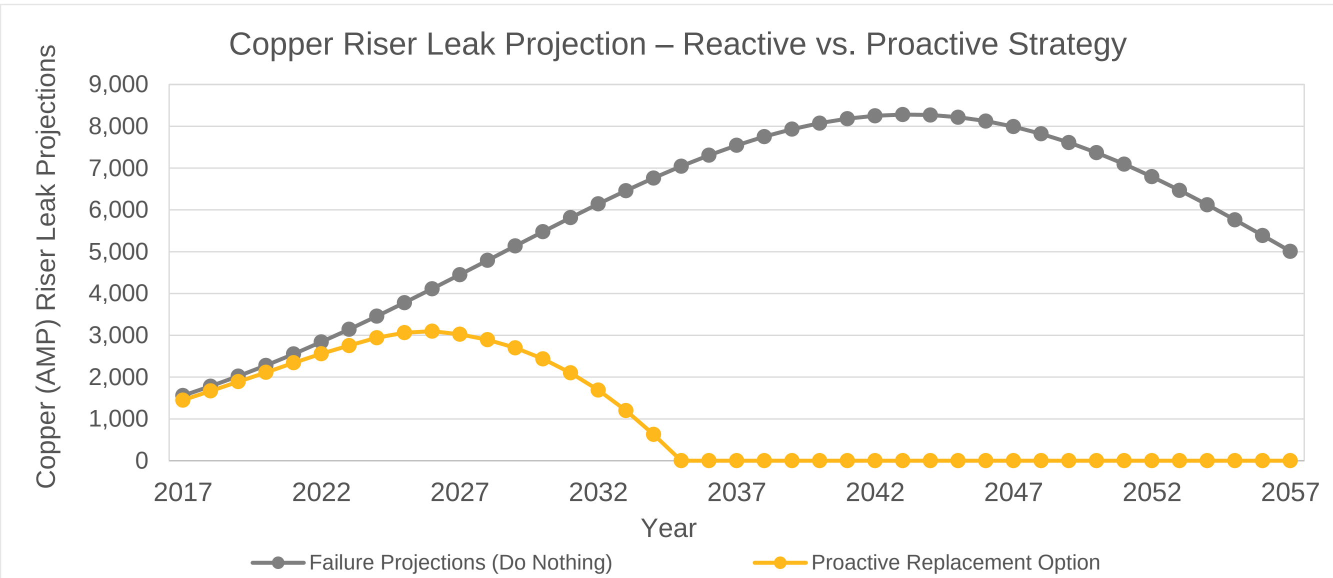

Figure 5.2-52: Copper Riser Leak Projection – Reactive vs. Proactive Strategy

EGI continues to evaluate asset condition and adjust its strategy accordingly to manage the integrity of AMP-fittings. The current annual service replacement program continues to manage the failing and non-compliant riser assets. Risers continue to be monitored under the Leak Survey and Corrosion Survey programs.

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5.2.8 Pipe Capital Expenditure Summary

EGI has spent an average of $60M and $115M annually in the EGD and Union rate zones respectively for the Distribution Pipe asset class. The total average capital spend is forecasted to be $162M (EGD RZ) and $158M (Union RZ) as summarized in **Table 5.2-4** and

Table 5.2-5. The Distribution Pipe capital is further summarized as part of EGI's total 10-year capital plan in **Section 6.**

Table 5.2-4: Pipe Capital Summary ($ Thousands) – EGD Rate Zone

Program/Project Name	2021	2022	2023	2024	2025	Five-year Forecast
Integrity Digs and Retrofits	**16,953**	**14,590**	**2,051**	**10,157**	**6,134**	**49,884**
Corrosion Prevention Program	**3,142**	**3,069**	**3,222**	**2,195**	**2,409**	**14,037**
Main Replacements	**137,921**	**133,939**	**48,555**	**81,063**	**68,022**	**469,500**
Emergency Replacement Program	2,441	2,433	2,564	2,489	2,644	12,572
Vintage Steel Mains Replacement Program	112,138	119,615	39,143	72,500	57,566	400,962
NPS 20 Lake Shore Replacement (Cherry to Bathurst)	78,270	47,823	-	-	-	126,093
NPS 12 St. Laurent Aviation Pkwy	305	33,740	1,987	-	-	36,033
NPS 12 St. Laurent Queen Mary/Prince Albert	122	12,578	680	-	-	13,379
St. Laurent Phase 3 St. Laurent Plastic - Montreal to Rockcliffe St. Laurent Plastic - Coventry/Cummings/St Laurent St. Laurent Plastic - Lower Section	12,761	2,352	-	-	-	15,113
NPS 12 Martin Grove Rd Main Replacement: Lavington to St. Albans Road	-	-	512	21,524	793	22,830
NPS 10 Glenridge Avenue, St. Catharines	-	-	558	7,360	7,213	15,131
General Main Replacement Program	**1,688**	**-**	**2,320**	**-**	**-**	**4,007**
Vintage Plastic Aldyl A Replacement Program	**21,654**	**11,892**	**4,528**	**6,074**	**7,812**	**51,959**
Relocations	**6,104**	**11,799**	**12,436**	**12,074**	**12,822**	**55,235**
Service Relay Programs	**37,886**	**38,261**	**43,621**	**46,384**	**59,184**	**225,336**

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Program/Project Name	2021	2022	2023	2024	2025	Five-year Forecast
AMP-fitting Replacement Program (Copper Risers)	12,013	11,287	13,898	16,187	25,828	79,213
Service Relay Program	25,873	26,974	29,724	30,197	33,356	146,123
EGD Rate Zone Total	**202,005**	**201,659**	**109,886**	**151,872**	**148,571**	**813,993**

Table 5.2-5: Pipe Capital Summary ($ Thousands) – Union Rate Zones

Program/Project Name	2021	2022	2023	2024	2025	Five-year Forecast
Integrity Digs and Retrofits	**38,819**	**30,370**	**30,007**	**22,595**	**20,077**	**141,868**
INTE: North Shore - Section A: Retrofit ECDA to ILI	14,674	-	-	-	-	16,674
Corrosion Prevention Program	**10,012**	**12,365**	**9,193**	**9,000**	**9,186**	**49,756**
Main Replacements	**191,743**	**63,886**	**44,293**	**67,999**	**37,017**	**404,939**
Steel Mains Replacement Program	155,154	39,138	12,949	33,016	13,472	252,567
Port Stanley Line Replacement	-	-	-	616	25,344	25,960
Kirkland Lake Lateral Replacement	733	19,715	-	-	-	20,449
London Lines Replacement	119,711	10,104	-	-	-	129,815
Windsor Line Replacement	8,802	-	-	-	-	8,802
Vintage Plastic Aldyl A Replacement Program	-	-	-	1,948	3,869	5,817
Bare and Unprotected Steel Pipe Replacement Program	15,618	14,160	12,405	14,494	-	56,678
Class Location Program	20,971	10,588	12,519	12,256	13,007	69,340
Relocations	**32,533**	**29,208**	**30,816**	**30,168**	**32,016**	**154,741**
Service Relay Program	**7,284**	**7,375**	**7,915**	**7,883**	**8,510**	**38,967**
Union Rate Zones Total	**280,391**	**143,204**	**122,225**	**137,644**	**106,807**	**790,271**

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5.3 Distribution Stations

The Distribution Stations asset class is comprised of facilities and assets whose primary purpose is to reduce pressure from a system operating at higher pressure to a system operating at lower pressure and to provide over-pressure protection to the lower-pressure system. Depending on the facility, additional purposes may include gas metering, odourization and monitoring.

This asset class is comprised of approximately 35,000 sites throughout Ontario. This includes all natural gas entry points into the EGI distribution network, control points throughout the network and delivery points to end-use customers. Distribution Stations is organized into three subclasses based on function:

- **Stations with Auxiliary Equipment**: System and customer stations reduce upstream pressure and distribute natural gas to pipeline systems operating at lower pressures and/or customers and employ additional equipment to ensure the safe and reliable distribution of natural gas.
- **Distribution System Stations** reduce upstream pressure and distribute natural gas to a downstream gas main.
- **Customer Stations** reduce upstream pressure and deliver to a downstream customer that consumes the natural gas with a total connected load greater than 12 m^3/h and with a delivery pressure to the customer of 14 kPa or greater.

EGI monitors the industry for incidents that may be relevant to EGI's assets. As such, EGI has assessed the potential for an incident on a low-pressure system such as that which occurred in Merrimack Valley, Mass. where a distribution system was over-pressured. EGI took some immediate measures to review procedures and records and ensure that sense lines were inside the perimeter of regulation stations. EGI is continuing to evaluate the risk in each of these installations and determine whether additional layers of protection are required to bring the risk to broadly tolerable or as low as reasonably practicable.

The current station rebuild and replacement rate is inadequate to prevent the average age of the population from increasing. With more than 34,000 stations of varying degrees of complexity and criticality, EGI is developing analytics to establish age, condition and risk so as to develop maintenance and replacement strategies that balance risk, cost and performance.

As EGI continues to review operating standards in each rate zone and the use of various equipment and fittings, plans will be developed to bring these into alignment in a way that balances risk, cost and performance. An example would be the addition of fire suppression systems at gate stations to ensure compliance with applicable codes and standards.

5.3.1 Distribution Stations Objectives

Objectives of the Distribution Stations asset class are listed in **Table 5.3-1.**

Table 5.3-1: Distribution Stations Asset Class Objectives

Asset Class Objective	
System Integrity and Reliability	Maintain distribution stations to meet or exceed codes, standards and the requirements of applicable governmental authorities for safety and operational effectiveness. This includes ensuring the system has the capacity to reliably meet current and future customer demand.
	Ensure the safe and reliable delivery of natural gas to end users.
	Use cost, risk and performance information to drive asset-related decisions.
	Continuously evolve the understanding of condition and risk associated with station assets.

The performance measures for the Distribution Stations asset class are as follows:

- Number of unscheduled visits per station
- Number of events where pressure is controlled via Over Pressure Protection (OPP) device
- Number of service disruptions
- Number of over-pressure events (failure to control pressure above OPP set point)

To achieve the Distribution Stations asset class objectives listed in **Table 5.3-1**, asset investment decisions are governed by the life cycle management strategies outlined in **Table 4.1-1**.

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5.3.2 Distribution Stations Hierarchy

The asset subclass hierarchy for the Distribution Stations asset class is illustrated in **Figure 5.3-1**.

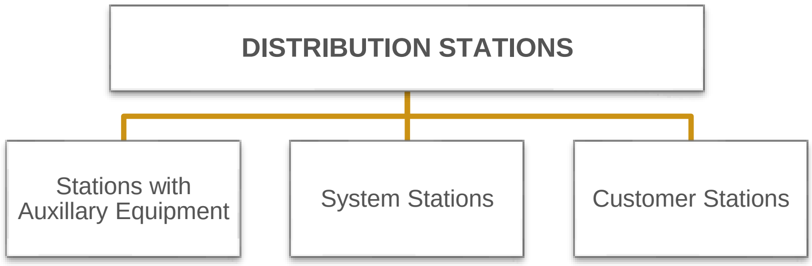

Figure 5.3-1: Distribution Stations Hierarchy

Figure 5.3-2 shows the station hierarchy by station type. Note that there are many possible configurations of distribution station assets downstream of the entry point into the distribution system. **Figure 5.3-2** is for illustrative purposes only and is not meant to display all possible configurations.

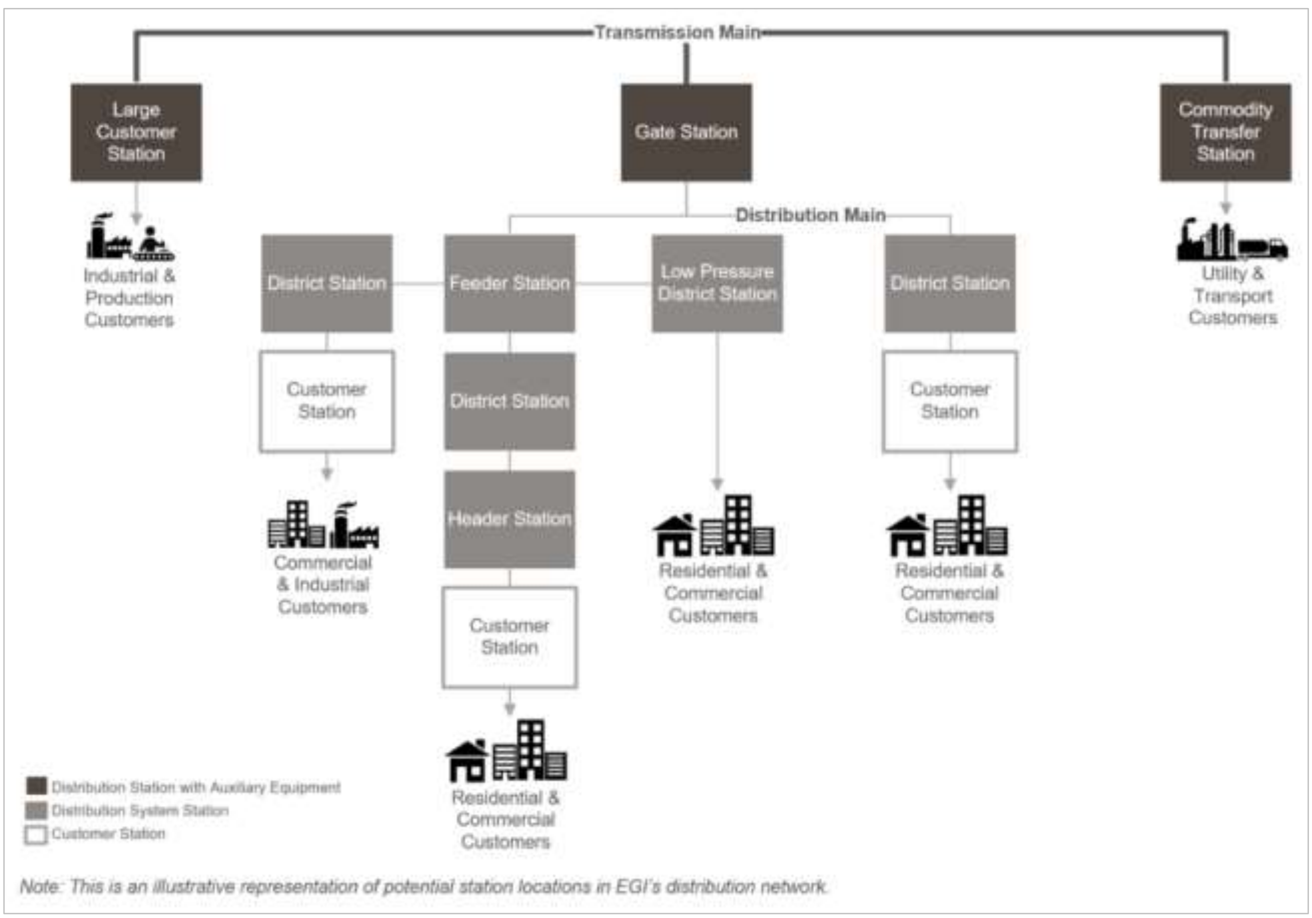

Figure 5.3-2: Station Hierarchy by Type

The Distribution Stations asset class includes the following asset component sub-systems:

- Pressure control
- Station valves
- Strainers and filters
- Piping systems
- Heating system (boilers and heat exchangers)
- Telemetry system
- Odourization system
- Measurement system
- Civil and site assets

Figure 5.3-3 depicts the typical schema and interconnection of systems associated with distribution stations. Station components and layout will vary based on the design, type and function of the station. A typical example of a station in the Station with Auxiliary Equipment subclass consists of the following system components: the inlet valve assembly for isolating and/or bypassing the station, the measurement system to accurately track the gas flow or volume, the heating, pressure control and odourization systems, the outlet/supply valve assembly and the outlet piping. These systems are interconnected through the telemetry system, which monitors and controls the operation and performance of each station component.

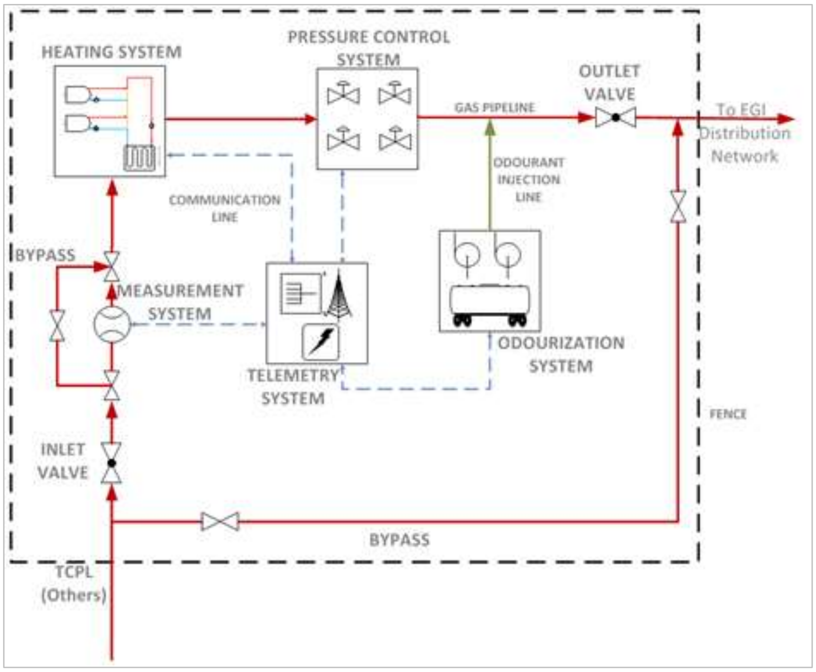

Figure 5.3-3: Station Components

The **pressure control** components control and regulate gas pressure from a higher pressure (inlet pressure) to a set lower pressure (outlet pressure). Pressure control equipment typically consists of operator regulators, monitor regulators, relief valves and slam-shut devices. Operator regulators control pressures while monitor regulators, relief valves or slam shut devices provide over-pressure protection in the event the operator regulator fails. Regulators are classified into four types: pilot-operated boot, pilot-operated non-boot, spring type regulators and pilot-operated control valves. Relief valves provide an audible and odor notification in the event of operator regulator malfunction.

The **station valve** components control the flow of gas through the station and include all inlet valves, outlet valves, bypass valves and component isolation and process valves. Station valves are used to direct flow, isolate station components and shut down gas supply for planned or unplanned events.

Strainers and filters are applied to remove particles of dirt from the gas before they can damage downstream system components such as regulators, pilots, meters or other equipment.

The **piping system** within stations is comprised of the pipe connecting each of the component groups, as well as ancillary piping and tubing. Ancillary piping includes glycol piping for the heating system, tubing for pressure control and piping and tubing for the odourization system. Piping may be installed below- or above-grade with pipe supports and may be insulated to

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retain heat or for noise attenuation. Protection of the piping system consists of underground corrosion control systems and above-ground high performance coating and paint.

The **heating system** components ensure that gas temperatures within the distribution system remain above a site-specific targeted setpoint, as the reduction in temperature caused by pressure regulation can have detrimental effects on equipment performance. The heating system is comprised of two sub-components–the boiler and the heat exchanger. The pressurized boiler heats and circulates glycol through a glycol loop to the heat exchanger, which transfers heat to the gas prior to pressure control reduction. Heating systems may also be comprised of small component heaters or heat trace systems that are used for thermal protection of critical components such as regulators and pilots.

The **telemetry system** connects station equipment to a network that remotely transmits station performance information to centralized gas control management for monitoring and control. Information such as inlet and outlet pressures and temperature, gas flow rate, odourant injection rate and other critical characteristics of station performance are monitored in real time. Typical sub-components include:

- Programmable Logic Controller (PLC) / Remote Terminal Unit (RTU) as the central processor
- Pressure and temperature sensors and transmitters
- Gas monitors
- Communications devices and antenna towers
- Power supply, UPS and backup generators and other electrical assets
- Weather systems

The **odourization system** components are responsible for the introduction of odourant into the gas stream to ensure gas is detectable at low concentrations as natural gas is odourless in its basic state. Odourant injection is automated at all stations at the entry point to the gas distribution network. Sub-components of the odourization system include:

- Odourant tank
- Odourant pumps
- Injection point with sight glass
- Odourant containment
- Meters, valves, tubing, controllers
- Atmospheric monitoring devices
- PLCs

The **measurement system** components provide a corrected volumetric measure of the amount of natural gas flowing through a particular site. Measurement devices are used in customer stations as a custody transfer point between EGI and the customer, subject to the MXGI program in **Section 5.4.5.1**. EGI uses many different meter types and electronic volume correcting equipment to calculate pressure and temperature compensation factors in real time. At customer or system stations where the design requires, EGI incorporates measurement devices to measure the rate of gas flow through its system. These measurement devices are critical for calculating the demand requirements (rate of odourant flow, heating system temperature requirements, etc.) for other station components.

Civil assets in the Stations with Auxiliary Equipment subclass can include individual buildings for housing telemetry assets, heating/boiler equipment, the odourization system, the pressure control system and other miscellaneous equipment. Civil assets also include fencing, property lighting, security systems, piping supports and barriers, water management systems such as culverts and ditches and general property.

5.3.3 Distribution Stations Inventory

Table 5.3-2 lists the inventory details for the Distribution Stations asset class.

Table 5.3-2: Distribution Stations Asset Class Inventory

Asset Subclass	EGD Rate Zone	Union Rate Zones
Stations with Auxiliary Equipment	**168 Stations**	**389 Stations**
Pressure Control	550	1,787
Valves	989	5,964
Filter	N/A	413
Flow Meters	114	295
Heating System - Boilers	143	554
Heating System - Exchangers	59	277
Odorization	194	147
Telemetry	1,083	1,055
Distribution System Stations	**4,928 Stations**	**2,646 Stations**
Pressure Control	14,527	5,077
Valves	3,224	8,405
Filter	N/A	734
Flow Meters	20	133
Telemetry	161	125
Customer Stations	**12,056 Stations**	**14,594 Stations**
Pressure Control	29,753	18,899
Valves	2,871	2092
Filter	N/A	2,700
Flow Meters	11,785	24,691
Telemetry	49	47
Rental Refueling – Large and Mobile	10	1
Refueling – Small (VRA)	210	N/A
Utility Refueling	19	3

Note: The inventory for meters and regulators (discussed in **Section 5.4.3**) also includes meters and regulators located at customer stations and included in the inventory figures above (EGD rate zone only).

In the Union rate zones, some subclass inventories (Local First Cut Regulator Sets, Remote First Cut Regulator Sets, and Below-ground and Internal Piping Systems) are not currently available. As part of integration activities, inventory tracking processes will be harmonized over time.

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5.3.4 Distribution Stations Condition and Strategy Overview

Asset Subclass	Avg. Age (Year)	Condition	Risk / Opportunity	Maintenance Strategy	Replacement / Renewal Strategy
Stations with Auxiliary Equipment	See **Table 5.3-3.**	Assets in the Stations with Auxiliary Equipment subclass are inspected and maintained on a regular basis in accordance with operating standards. At certain sites, the telemetry, pressure control and heating system components were found to have the following deficiencies: obsolescence, performance issues and non-standard configurations.	Risks identified for Stations with Auxiliary Equipment: **Employee and Contractor Safety Risk and Public Safety Risk**: Impact on surrounding population in the event of loss of containment **Financial Risk**: Commodity loss, repair costs and regulatory penalties **Operational Risk**: GHG emissions and loss of service to customers	The maintenance strategy for Stations with Auxiliary Equipment includes: • Facilities Integrity Management Program (FIMP) inspections • Pressure Control and Protection Inspection Standard • Equipment operating standards for auxiliary components	The replacement / renewal strategy for Stations with Auxiliary Equipment includes: • Stations with Auxiliary Equipment Replacement strategy • Compliance Remediation strategy • Obsolete Heating Equipment strategy • Odourization strategy • Telemetry strategy • Stations Retrofit strategy for Integrity pipe • Stations Capital Upgrade program • Facilities Integrity Management program
Distribution System Stations	See **Table 5.3-5.**	Distribution System Stations assets are inspected through field condition survey assessments to identify the existence of boot style regulators, below- ground installations, non-conforming configurations and vintage/obsolete components, contributing to a higher potential of failures and operational issues. Distribution system stations have a relatively constant and low growth rate in failure events over the next 20 years under the historical and current replacement and renewal programs. At this time, Union rate zone assets have not been incorporated in the Asset Health Review (AHR) program–a detailed plan is being developed for their inclusion.	Risks identified for Distribution System Stations and Customer Stations: **Employee and Contractor Safety Risk and Public Safety Risk**: Public impact, threat to over-pressuring customer piping **Financial Risk**: Repair and high maintenance costs, customer supply impact **Operational Risk**: Loss of service to customers	The maintenance strategy for Distribution System Stations includes: • Distribution Integrity Management Program (DIMP) • Pressure Control and Protection Inspection Standard	The replacement / renewal strategy for Distribution System Stations includes: • Distribution System Station Replacement Strategy • Header Station Replacement program • Regulator and Relief program • Vaulted Stations Replacement program • Stations Painting program • Stations Capital Upgrade program • Distribution Integrity Management program
Customer Stations	See **Table 5.3-7**.	Customer Stations assets are inspected through field condition survey assessments to identify the existence of boot style regulators, below- ground installations, non-conforming configurations and vintage/obsolete components, contributing to a higher potential of failures and operational issues. Customer stations are forecasted to have a slight increase in failure events with the current replacement pace over a 20-year projection.		The maintenance strategy for Customer Stations includes: • DIMP • Pressure Control and Protection Inspection Standard	The replacement / renewal strategy for Customer Stations includes: • Customer Station Replacement program • External Regulator Room program • Stations Painting program • Stations Capital Upgrade program • DIMP

5.3.5 Stations with Auxiliary Equipment

The assets in the Stations with Auxiliary Equipment subclass are the most complex distribution stations within EGI - most are uniquely configured and involve the highest pressures and volumes. These stations include entry points into the gas distribution system and require additional equipment, which are not required in other stations downstream of the network.

Station components can vary greatly depending on the station's purpose and design complexity. Stations with auxiliary equipment have components that consist of piping, meters, regulators, valves, filters, separators, heaters, odourant, controls, and in some cases, structures. These stations are grouped according to function:

- **Gate and Transmission Stations** accept gas from a transmission company's pipeline (EGI or other) and supply gas to the distribution system, acting as the custody transfer and entry points of natural gas into the network. Station components included in these stations are pressure control, odourization, measurement, station valves, heating and telemetry. Gate stations typically accept incoming gas pressures from the transmission company at high pressures and regulate to distribution pressures. In a particular location, a single gate station can supply gas to over 600,000 customers.
- **Feeder Stations** are large regulator stations within the gas distribution system. Station components included in feeder stations are pressure control, measurement, gas pre-heating and telemetry. Feeder stations typically accept incoming high pressures and regulate to distribution pressures. This type of station is traditionally located within the Greater Toronto Area.
- **Commodity Transfer Stations** are stations where gas is bought from or sold to another utility or transporter.
- **Large Customer Stations** refer to a commercial or industrial station where the downstream system served is a single service.

The majority of station sites have above-ground components, with some piping and operating equipment located below ground. All gate and transmission, feeder, commodity transfer and large customer station sites are located on EGI-owned property within fenced and controlled access compounds. The additional station equipment (i.e. filtration, heating systems and/or odourization) at these sites present increased hazards that require enhanced attention. These sites are the custody transfer point and critical pressure control location from the transmission company's pipelines into the EGI distribution network or to a large customer site.

Table 5.3-3 represents the age of the various systems components and life expectancy at all station sites for this subclass. The expected lifespan for each system was based on evaluations and Subject Matter Advisor (SMA) interviews and is aligned with the current asset population and historical replacement strategy.

The age of individual systems is used for evaluation, rather than the age of the original activation of the station site, as individual station components are replaced based on their condition. Typically, the oldest assets tend to be the pressure control components, which have the longest expected life span.

Table 5.3-3: Estimated Life Expectancy for Stations with Auxiliary Equipment

Station Component	Expected Life (SMA input)		Average Asset Age (Years)		Maximum Asset Age (Years)	
	EGD RZ	Union RZ	EGD RZ	Union RZ	EGD RZ	Union RZ
Pressure Control	37 to 45	Up to 37	16	17	57	52
Odourization	19 to 28	20 to 25	13	14	23	29
Heating System	18 to 24	10 to 38	12	12	22	47
Telemetry	14 to 23	9 to 20	13	7	33	38

Table 5.3-3 shows both rate zones have differences in the expected life of station components, the actual average age and the maximum asset age. This is expected due to different design standards and maintenance strategies. As part of integration activities, best practices for engineering design and operating standards are being applied to the combined station asset population to better understand asset condition.

5.3.5.1. Condition Methodology

EGI station assets are inspected and maintained on a regular basis in accordance with operating standards. For example, the pressure control system is inspected on a frequency that considers inlet maximum operating pressure (MOP), inlet pipe size, station type and regulator type. This can be as frequent as a weekly inspection for stations with a higher inlet MOP and inlet pipe size. Inspection results and trouble call history are recorded and analyzed to understand asset performance, condition and health.

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EGI is enhancing the Facilities Integrity Management Program (FIMP), which provides the framework to identify threats, monitor facility conditions and manage Integrity data. FIMP applies to stations that meet the following criteria:

- Any station interconnected between EGI and any other gas transmission company, distribution utility or production facility that supplies gas into or receives gas from the EGI network and is not the final point of use.
- All facilities connected to or including pipe operating at or above 30% SMYS based on MOP and not currently inspected by the Transmission Integrity Management Program (TIMP). If these stations do not have auxiliary equipment, they are considered to belong in the Distribution System Stations asset class (see **Section 5.3.6**).
- Facilities where the following equipment is used in the direct conditioning of gas that is being used further downstream.
    - Heat exchangers as part of a boiler system
    - Equipment containing glycol used to directly heat gas
    - Liquid separation equipment (excluding separation used for control or fuel gas)
    - Filters (excluding single cartridge/element filters)
    - Control valves
    - Odourization

Approximately 92% of the assets in the Stations with Auxiliary Equipment subclass are within the scope of the FIMP. The FIMP will provide direct evidence in the form of quantifiable data on assets to supplement existing condition information. The remainder of the population condition will be assessed through routine maintenance and visual condition inspections.

5.3.5.2. Condition Findings

The condition at each station is unique (in terms of asset condition, obsolescence and compliance). Station components may vary in age due to the replacement history of the site. Historically, station issues have been identified when existing maintenance procedures are executed. A list of typical findings can be found in **Table 5.3-4**.

Table 5.3-4: Typical Station Issues

Issue	Description
Construction and Configuration	Station configurations are not in compliance with current design standards. Electrical configurations not in compliance with current design standards may result in a higher potential for electrical supply failures, employee safety concerns and violation of ESA standards. Lack of adequate backup power contributes to a high probability of station power loss during hydro outages, resulting in system and monitoring failures. Leak containment issues contribute to potential code compliance violations and potential high cleanup costs in the event of loss of containment for glycol, odourant, etc.
Function	The asset is unable to deliver the required demand (i.e., insufficient gas supply, heating requirements, over-working components, etc.) and can result in loss of supply to customers. Equipment inaccuracy results in incorrect gas measurement systems and potential revenue loss. Sealing issues increase the probability of asset failure and downstream over-pressure situations.
Operability	Operating difficulties contribute to increased maintenance costs and potential employee safety concerns.
Maintainability	The asset requires frequent maintenance calls and adjustments. Component accessibility issues contribute to increased maintenance costs, potential asset failures and employee safety concerns.
Components	Parts are no longer available, repairs result in long downtime, or repair costs are excessive. Glycol conditioning issues indicate the degradation of heating system internal components, which result in higher maintenance costs and decreased component reliability Communication issues contribute to electronic component failures, loss of remote monitoring, alarming and control. Recurring component issues contribute to increased failures and component reliability concerns. Corrosion is an indication of component degradation and less reliable assets Insulation damage promotes rapid corrosion growth on piping.

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Issue	Description
	Building issues can result in leaks and lack of component protection, causing premature failure and less reliable assets.
External Factors	Dirt and debris increase the probability of failure and downstream over-pressure situations. Damaged components contribute to increased maintenance costs and potential employee safety concerns. Pipe heaving occurs due to inadequate heating supply or improper construction methods, resulting in undue stress to piping and other components. Improper support can result in movement or settlement, causing undue stress to piping and components. A sinking foundation causes stress in piping and other critical components. Damages to fences or other physical security equipment could result in vulnerability threats.

In addition to maintenance inspection results, the condition and health of station components may be subject to further engineering analysis and future FIMP inspections. These stations are evaluated based on the following:

- The age of critical components, such as regulators, boilers, RTU, etc.
- The performance of the asset, such as known operational problems
- Asset history and the evaluation of failure events
- SMA input

To better understand asset condition, the FIMP will provide direct assessment data as described in **Section 5.3.5.1**.

5.3.5.3. Risk and Opportunity

Assets in the Stations with Auxiliary Equipment subclass are a vital part of the distribution network; as such, failures have significant consequences and must be avoided. Mitigation strategies to reduce risk to the lowest practicable level include redundancy of critical systems and a comprehensive inspection and maintenance program.

When station components are not maintained, the following are types of failures and the likely consequences (failure scenarios) are observed for this asset subclass:

- **Loss of Pressure Control**: Pressure control failures could cause an over-pressure or under pressure scenario.
    - **Over-pressure Event**: Stations are the delineation between different operating network pressures. Failures causing over-pressure situations result in the upstream higher pressure network interacting with the downstream lower pressure network. In this scenario, the pressure of the downstream network increases to levels beyond which it is rated. Over-pressure could lead to component failure in the downstream network, over-stressing pipe or fittings, loss of containment and gas entering customer premises if the customer regulator fails. The potential for fire or explosion is increased in an over-pressure situation.
    The frequency of pressure control failure is dependent on the configuration of the station. A station with a single regulator and single run will fail more frequently than a station with double regulators and double runs. Each of these could result in a release to the environment, leading to potential ignition or explosions.

      The consequence of an overpressure event from a financial impact includes commodity loss, service disruptions, increased network leak surveys and system checks, repairs or replacement of company-owned property or damages to public, commercial or industrial property. Pressure control failures may lead to unintended GHG emissions of natural gas to the environment, impact EGI’s reputation and fail to meet the expected high levels of operational reliability.
    - **Under-pressure Event**: Under-pressure at a station can lead to loss of service for customers. This is of particular concern for industrial customers, who expect a reliable natural gas supply for processes, as well as for heating needs during colder periods. Stations approaching design capacity could experience under-pressure situations, loss of service to customers and station equipment performing beyond recommended operating limits.

  Typically, the pressure control design includes redundancy with a method of over-pressure protection to reduce the likelihood of a pressure control failure.
- **Loss of Measurement System Function:** Measurement equipment can be used to accurately inject odourant into the pipeline. Loss of measurement functionality could lead to improper odourant levels (undetectable gas leaks), inaccuracy of gas measurement and inaccurate billings of commodity transfer which could result in volume billings or purchase disputes.

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- **Loss of Odourant System Function**: The odourant system adds the odour in natural gas so that it is detectable in the event of a release. Failure of the odourant injection system could result in leaks not being readily detectable which could lead to service disruption implications, commodity losses from undetected leaks, public property damages or fines from the technical regulatory authority. Reputational and financial risk may result from the reduction in emergency and unplanned callouts to unreliable odourant injection systems. Inoperable odourant systems would lead to a failure to maintain proper odourant levels as mandated by code requirements, potentially impacting the safety and reliability of the gas distribution network.
- **Loss of Heating System Function**: Loss of the heating system function could result in two scenarios (frost heave or pressure control failure due to the freezing of station components) that could result in the loss of pressure control and potentially leading to an over-pressure or under-pressure situation. Frost heave occurs when cooling of the gas due to the pressure reduction causes an upwards swelling of soil around public or private property near the gas main. The financial impact includes commodity loss, service disruptions, increased network leak surveys and system checks, repairs or replacement of company-owned property, or damages caused to public, commercial or industrial property. Inoperable systems will lead to a failure to maintain operational supply to customers.
- **Valve System Malfunction**: The frequency of a valve malfunction is low. Inoperable station valves prevent isolating gas flow within the station. This would lead to isolation of the station where available (up and/or downstream of the location), increased maintenance and potentially lead to higher response times.
- **Loss of Telemetry System Function**: Failure of real-time monitoring would cause a delay in responding to system operation problems or emergencies. Stations with an older telemetry system have a higher failure frequency. Without the telemetry system, there is no visibility to the performance and operation of EGI’s system, causing increased callouts, emergency system repairs and greater patrols. Failures of the telemetry system could also be caused by cybersecurity attacks into the communications network.
- **Loss of Electrical System Function**: Loss of the electrical system function will impact the odourant, telemetry and heating systems as all rely on electrical power or backup power systems to function properly. Without a power supply, the failures described for each station component can exist. The frequency of losing power at a station depends on the frequency of electricity outages in the area, third-party damage and backup power system failures.

Equipment failures can occur in any asset subclass component and its impact is dependent on site location and redundancy, which could affect response times if a failure occurs. The impact of each system failure is different; however, there are some interdependencies between system failures. The extent of impact is dependent on the station location (i.e., whether the station is in a populated or remote area), the number of customers serviced by the station and whether the station is a single-feed or multi-feed system. The subsystems within these stations have interdependencies which may impact the reliability and performance of other systems. Therefore, the complexity of failures in one subsystem may lead to potential failures of other subsystems. For example, the measurement system is used to both measure gas flow and calculate the proper odourant injection rate. The response times to address equipment failure can vary depending on the location of EGI’s response team, reinforcing the design strategy to include redundancy where appropriate.

The risk for assets in the Stations with Auxiliary Equipment subclass is dominated by financial risk, which may require fixing any damages to public property, relights due to service disruption, commodity loss, replacing and repairing company property and any regulatory penalties. Failures at these stations could impact gas supply to EGI’s customers, leading to decreased operational reliability and reputational impacts. The public safety and employee and contractor health and safety risks for these assets are higher if the station is located in an urban or developed area due to a high potential impact on the surrounding population. Operational risks identified include GHG emissions and loss of service to customers.

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5.3.5.4. Strategy Outcomes

The strategies for the Stations with Auxiliary Equipment asset subclass support the proactive replacement of stations based on obsolescence and condition:

Stations with Auxiliary Equipment Replacement Strategy

This strategy targets the replacement and/or rebuild of station components at sites prioritized based on condition, age and observations identified through site inspections and SMA reviews. Station investments are selected based on value framework assessment results and compliance/design standards. The goal of this strategy is to proactively replace or rebuild station components prior to end-of-life to reduce risk and maintain a safe and reliable distribution system. This is aligned with 2020 Customer Engagement survey results where customers are supportive of investing to maintain current levels of safety and reliability. Despite this strategy, there may be instances where reactive replacement occurs.

This strategy includes considerations to leverage resources and plan capital replacements in a thoughtful manner that can vary by site. Some considerations include:

- Replacement of components based on expected failure. For example, if the entire boiler system is in poor condition with a high expectation of system failure, the entire system is replaced (proactive).
- Multiple component rebuilds to benefit from combined resources and project scope. For example, if the boiler system is in poor condition with a high expectation of failure and the telemetry and odourization systems are currently approaching poor condition, all three systems are replaced (proactive).
- Replacement and upgrade of components evaluated to be at or approaching capacity, based on projected forecast demands. For example, if regulators are evaluated to be approaching capacity in the upcoming year, components will be upsized to handle the appropriate projected system demands (proactive).
- Replacement of individual component assets as they fail. For example, a failure of one of the pumps within the boiler system results in the pump being replaced (reactive).

Compliance Remediation Strategy

This strategy targets the elimination of compliance concerns at stations identified through engineering assessments and Process Hazard Analyses (PHAs), using a managed approach to monitor and address identified code compliance issues. The strategy targets individual station sites found to have compliance deficiency issues such as issues on access/egress, building codes and fire codes, venting and site security vulnerabilities, as well as environmental compliance approvals.

Obsolete Heating Equipment Strategy

This strategy targets stations with heating equipment that have reached end-of-life, with a focus on systems where there is a risk of a glycol spill. Natural gas heating equipment is used in many system and customer stations to help mitigate failure of equipment due to the freezing of liquids in the gas stream and moisture surrounding buried piping. Over many years of operation, a variety of heating systems have been used, resulting in varying equipment age and ultimately, equipment obsolescence. This work will maintain system reliability, ensure operating costs for heating systems are minimized and reduce the potential for glycol spills.

Odourization System Strategy

This strategy targets stations with older odourization systems, specifically those with compliance issues. The expenditures in this portfolio include investments to upgrade odourant systems to ensure compliance to current codes, such as replacing old tanks and painting rusted containment pans and tank stands. Additionally, performance capability will be added by installing heat tracer lines, heated cabinets, improved tank valves and indoor regulator panels. This work will help to ensure safe, compliant and continuous odourization and will help mitigate the risk of tank rupture, frequent freeze offs and nuisance odour calls.

Telemetry Strategy

This strategy aims to maintain reliable telemetry equipment and will focus on component replacements as these have a much shorter anticipated life span than other station equipment. Telemetry components have varying life expectancies and are upgraded to address obsolescence, communication issues, electrical configurations and backup power. Obsolete equipment cannot be replaced like-for-like if it is damaged and may compound communication issues. The scope of the Telemetry Strategy includes:

- Replacement and upgrade of telemetry instrumentation, electrical and power generation assets and telemetry communications assets
- Replacement and upgrade of servers and network devices such as firewalls, modems, routers, etc.
- Supply and installation of security assets (swipe card access, video surveillance and intrusion detection assets)
- Tower network expansion as required to augment communication pathways
- Computer terminal and server expansion to support central logbook repository, data analytics and data historians

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- Continued development of the maintenance layer at major stations and the implementation of capabilities to backhaul data from remote sites to enable video surveillance, swipe card access at all compounds and buildings and a central logbook repository for all sites

Stations Retrofit Strategy for TIMP Mains

The Stations Retrofit Strategy for pipelines covered under TIMP targets adding permanent in-line inspection assets (launchers and receivers) to existing stations upstream and downstream of pipelines operating at >30% SMYS. See **Section 5.2.5** for more details on the assets within the TIMP Mains asset subclass.

Stations Capital Upgrade Program

This program includes a number of risk remediation programs and general upgrade activities that are part of the core system and customer station work:

- **Obsolete Equipment**: As station facilities age, regulators and relief valves can become obsolete due to vendors no longer supporting specific types of equipment or may present maintenance and reliability concerns due to age. This initiative remediates all currently identified obsolete station equipment in the Union rate zones, improving system reliability and generating field efficiencies due to the reduced equipment variability and simplified maintenance procedures.
- **Regulator Freeze-offs**: As natural gas supplies into the pipeline systems change, natural gas quality can also change. Existing system stations that experience significant pressure cuts combined with elevated moisture content in the natural gas stream can cause freezing of regulators and loss of downstream customers. Sites of concern will continue to be addressed as needed.
- **Station Blankets**: Spend is also allocated to each region to ensure capital is available for unforeseen maintenance challenges, such as leaks or failures that require short turnaround times for remediation, particularly if no specific project is identified for the affected assets.
- **Frost Heave Mitigation**: This initiative targets stations presenting issues due to frost formation in below-grade soil. Mitigation techniques can include the addition of station heaters, or where frost heaving is less severe, the excavation and leveling of station sites. This program ensures the risk of leaks and piping failures are reduced to maintain system reliability. It also ensures maintenance challenges are reduced, such as when piping can spring out of place due to stresses imparted from frost heave.

Using these factors as a guide, work is ongoing to identify stations that will require replacement in the later years of the asset plan (2024-2045).

Facilities Integrity Management Program

See **Section 5.3.5.1**.

5.3.6 Distribution System Stations

The assets within the Distribution System Stations subclass reduce gas pressure from a network operating at a higher pressure to a network operating at a lower pressure depending on the needs of downstream natural gas main. These types of stations are typically located above-ground, with or without an enclosure and differ in size, operating pressure conditions, number of downstream connected customers and gas volume delivered. System station components consist of piping, meters, regulators, valves, and in some cases, limited pressure monitoring. System station function and components vary greatly depending on use and design complexity:

- **District Stations** operate within the gas distribution network and regulate the flow of gas from a higher pressure to a lower pressure. District stations are primarily used for pressure control and may have basic pressure monitoring capabilities (district stations with a gas pre-heating system are included in the Stations with Auxiliary Equipment subclass). District stations are typically located within roadway allowances and can be housed within a box enclosure, located above-ground without an enclosure or buried below-grade in a vault.
- **Header Stations** accept gas from any EGI pipeline system and feed a header service (a network of pipe on private property). Header stations are primarily used for pressure control. These stations are typically located above-ground and on private property. While header stations are a class in the EGD rate zone, it is not an identified class in the Union rate zones.
- **Commodity Transfer Station Without Auxiliary Equipment**: these stations mark the change of gas ownership from EGI and another party.
- **Ontario Producer Stations** are located at gas production wells within EGI's franchise area where gas enters the distribution system.

Distribution system stations consist of mechanical components with shorter lifespans relative to other gas-carrying assets (see **Table 5.3-5**). Based on Subject Matter Advisor (SMA) experience, this is broadly aligned with preliminary models predicting the useful life of regulators.

Table 5.3-5: Estimated Life Expectancy for Distribution System Stations

System Station Rate Zone	Expected Life (SMA Input)	Average Asset Age (Years)	Max. Asset Age (Years)
EGD Rate Zone	27 to 37	18	51
Union Rate Zones	27 to 36	21	60

Based on SMA input for a station's expected life, both rate zones have differences in the expected life of these assets compared to the actual average asset age and the maximum age of the current population. This is expected due to the different design standards and maintenance strategies employed. Integration activities are ongoing to harmonize best practices for engineering design and operating standards in both rate zones.

Although age is not the only factor in evaluating station asset condition, an increase in failure is seen as the asset approaches the end of its life. **Figure 5.3-4** displays the distribution system station population age demographics for the EGD rate zone.

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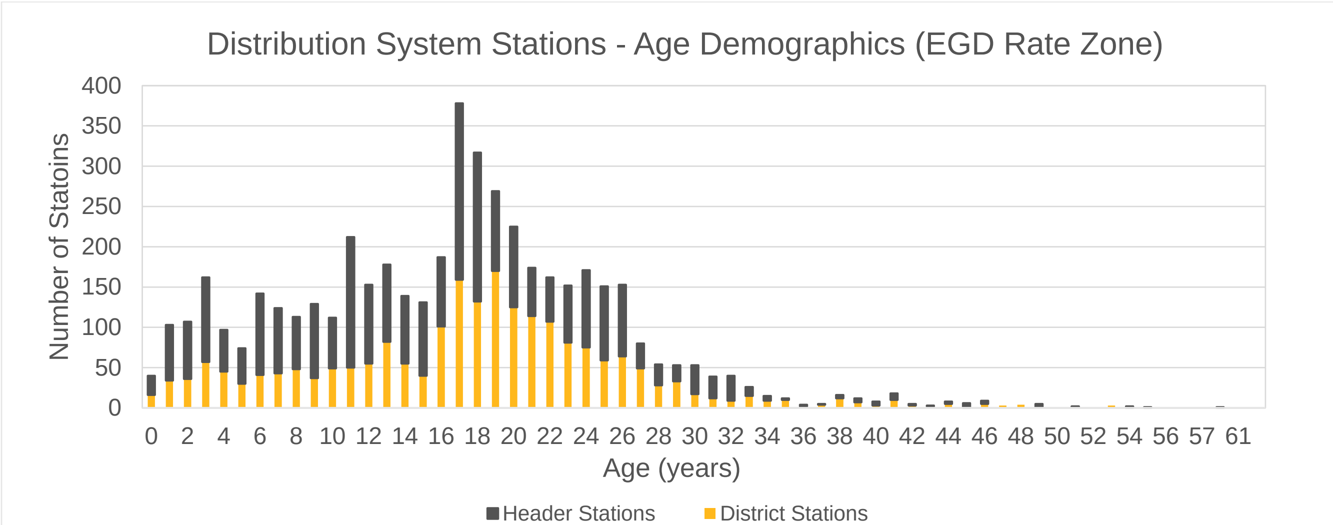

Figure 5.3-4: Distribution System Stations - Age Demographics (EGD Rate Zone)

Figure 5.3-5 displays the age demographics for distribution system stations in the Union rate zones. Two outliers in the number of stations at 19 and 30 years can be attributed to the integration of legacy asset information systems. The age data represents when the last asset was installed and may not reflect situations where existing assets remained within the station (i.e. pipe or valves that typically have longer lives). Work continues to understand the demographics of Union rate zone stations as part of integration activities.

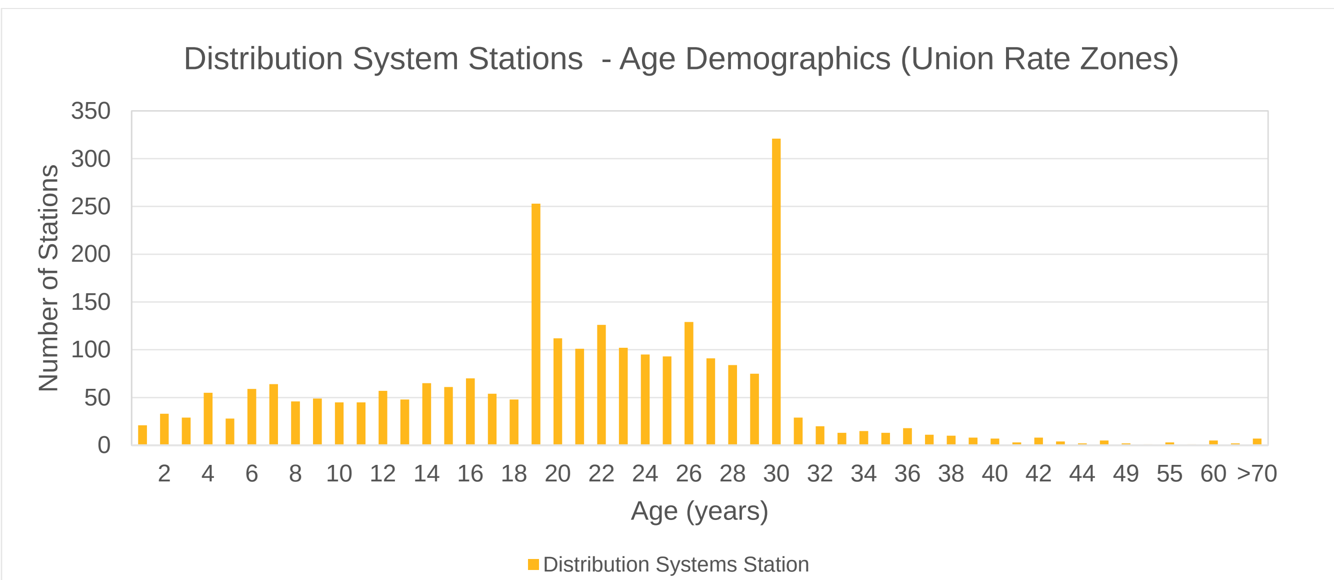

Figure 5.3-5: Distribution System Stations - Age Demographics (Union Rate Zones)

Distribution system stations are generally installed either above-ground or below-ground in a vault (see **Figure 5.3-6**) and typically installed on public right-of-way but can also be on private property or easements. Above-ground, they may be protected from the elements within a box enclosure or exposed to the elements. Below-ground vault locations can experience aggressive condition degradation from a wet environment, flooding or sidewalk/road runoff and may create confined spaces requiring specific procedures for safe entry. These assets can experience pipe coating degradation which can lead to corrosion. Flooding could impact the mechanical operation of the pressure control and valve systems.

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Figure 5.3-6: Examples of Distribution System Stations

5.3.6.1. Condition Methodology

The methodology for determining the condition of distribution system stations assets uses a combination of data analysis of the asset's failure and event history and a qualitative on-site condition assessment. These methods provide an understanding of the station asset age, past performance and future projected reliability. This methodology is also applied to customer stations assets (see **Section 5.3.7**).

The Distribution Integrity Management Program (DIMP) uses data analysis to make predictions about the life of distribution system station assets using widely-accepted and applied statistical principles. Reliability models are developed to understand the failure behavior and reliability of station assets. These models employ recurrent data analyses for repairable assets by fitting a statistical distribution or function to the data for the population. For repairable assets, the function for the data set can then be used to estimate important life characteristics of the asset such as reliability, conditional probability, intensity of failure at a specific time, its mean life and failure rate.

The calculated reliability for individual sites can be adjusted to reflect assets that are in worse condition than anticipated by the reliability models. **Figure 5.3-7** provides a visual representation of how evaluation from the field condition assessment is applied to adjust the reliability for the individual site.

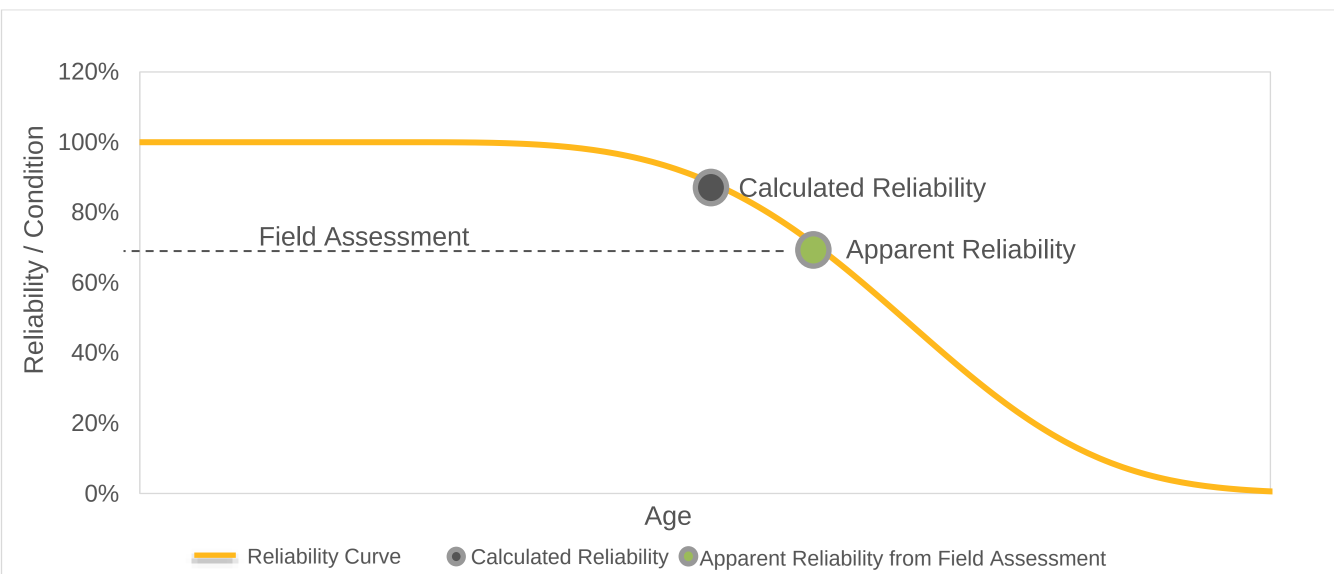

Figure 5.3-7: Station Reliability and Condition Assessment

On-site condition assessments are conducted to assess, classify and further understand condition details that cannot be determined through data analysis alone. **Table 5.3-5** outlines the specific condition evaluation criteria used to assess station components. These assessments inform the priority of individual stations for station replacement programs.

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Table 5.3-6: Evaluation Criteria for Station Components

Station Component	Condition Evaluation
Pressure Control	• Operating parameters for each regulator are correct (i.e., outlet pressure matches the correct set point) • Ability to lock up under zero flow condition • Responds appropriately to changes in outlet pressures and flows • Over-pressure protection device operates at its specified set point and capacity is adequate • Obsolete equipment and/or parts not available • Improper/non-standard configuration
Station Valves	• Difficult to operate/move freely • Leak to atmosphere • Damaged or inaccessible • Will not seal completely and gas flow cannot be isolated
Piping	• Presence of corrosion indicators • Damage to insulation or coating • Pipe heaving or movement
Other issues	• Level of corrosion • Signage or station protection • Issues impacting safety and the ability to perform maintenance inspections • Condition of paint and pipe coating • Performance of the components • Level of heaving or piping alignment • Overall site safety condition • Obsolete equipment no longer supported by product manufacturers

Other factors to be assessed by other groups (not on-site) include:

- Station capacity verification (to ensure the reliability of supply to EGI's growing customer base)
- Compliance with relevant codes and standards

5.3.6.2. Condition Findings

As assets age and degrade, they typically begin to fail at an increasing rate and the accumulation of those failures over time will begin to account for a greater proportion of the total population. Using historical failure event rates to model the projected failure events, **Figure 5.3-8** helps to illustrate this relationship over time and provides insight into the impact of projected future failure events on the asset population with the current replacement program applied.

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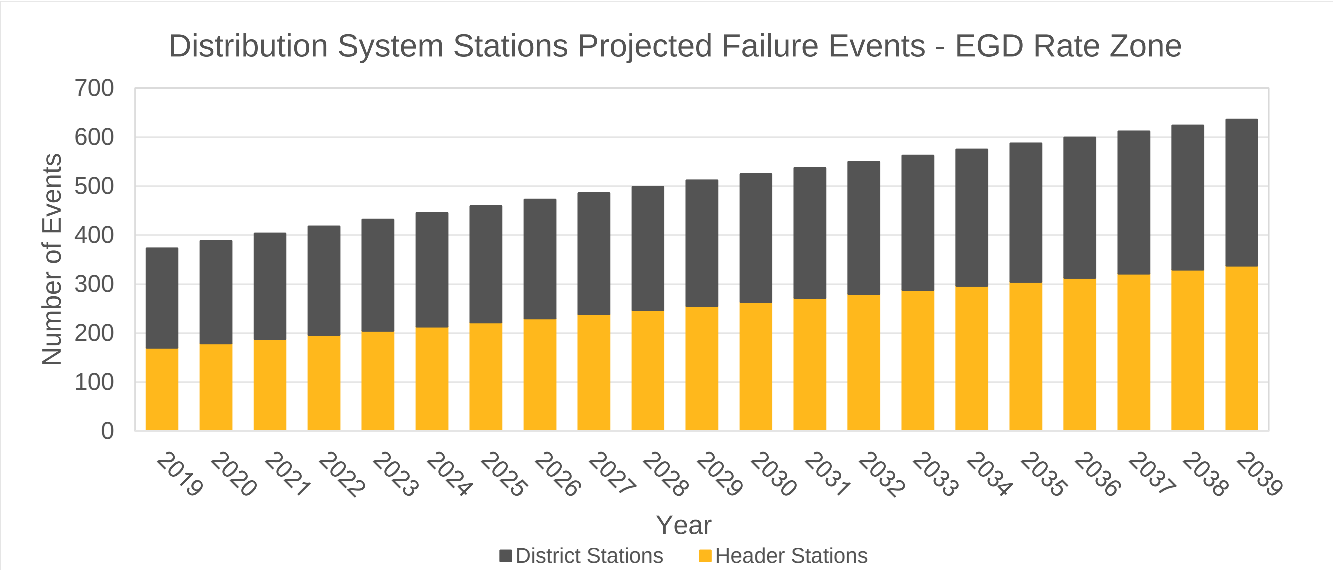

Figure 5.3-8: Distribution System Stations Projected Failure Events - EGD Rate Zone

Figure 5.3-8 reveals that distribution system stations have a relatively constant and low growth rate in failure events over the next 20 years under the historical and current replacement and renewal programs. At this time, Union rate zone assets have not been incorporated in the Asset Health Review (AHR) program. A detailed plan is being developed for their inclusion.

On-site condition assessments continue to be collected on an ongoing basis to thoroughly understand the condition of distribution system station assets. Results of the surveys (issues have been identified in the valve, pressure control or piping component groups) are actively addressed through reactive repairs or through replacement programs where appropriate.

The system station replacement programs are informed by condition surveys to reduce the risk of any issues observed. For example, boot-style regulators which use a combination of a flexible “boot” element and gas pressure to regulate downstream flow and pressure may be more susceptible to higher failure rates due to their design. This type of regulator station design has demonstrated susceptibility to failures caused by debris, particulates, hydrates and sulfur deposits. Adopting a new design philosophy to use alternative regulator models or including filtration minimizes the potential for downstream over-pressure events.

Another example of issues from field reviews of distribution system station sites have found non-conforming configurations or locations deemed to be potential hazards to safe site operation, such as clearance issues or potential threats from third-party damage. It is anticipated that these potential hazards may exist across the distribution system station population of certain vintages, when construction practices and standards were not consistently applied. It is also expected, in some cases, that local area development over time has encroached on the facilities resulting in higher risk of station damage from external influences, such as vehicle traffic or debris from above or compromised station supports.

Figure 5.3-9: The Joule-Thomson Effect on a District Station

Distribution system stations that experience a high differential pressure reduction from inlet to outlet pressure are associated with a higher risk of failure. For instance, as natural gas passes through the pressure control device, the gas temperature decreases approximately 4°C for each 700 kPa of pressure reduction (the Joule-Thomson Effect). High differential pressure control significantly decreases gas temperature (from high inlet pressure to lower outlet pressure). Stations where a high pressure reduction occurs can be subject to freezing of its station components, which may cause a loss of pressure control if there is moisture in the gas, heaving of the station piping if there is moisture in the ground surrounding the station, or the temperature reduction of the gas could cool the downstream piping and impact the surrounding grounds, including the potential to damage roads. The effects of the Joule-Thomson Effect are illustrated in **Figure 5.3-9**. Ice build-up is visible on the downstream components and the station assembly is misaligned due to heaving.

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5.3.6.3. Risk and Opportunity

The risks identified for distribution system stations are operational risk, financial risk, employee and contractor safety risk and public safety risk, which may lead to the following consequences:

- Public impact, threat to over-pressuring customer piping
- Repair and high maintenance costs, customer supply impact
- Loss of service to customers

These risks are also applicable to the Customer Stations asset subclass (**Section 5.3.7**). Risks are dependent on station design and location:

- **Over-pressure Event**: In an over-pressure event, the downstream network is operating above the designed maximum pressure. In addition to the risks discussed in **Section 5.3.5.3**, distribution system stations feeding low-pressure networks have additional safety consequences, as these networks are designed without individual regulators at customer meter sets, normally considered a second line of defense against potential piping over-pressure inside the customer's premises.
- **Loss of Pressure Control (Lock Up)**: A regulator locks up when it cannot completely shut off gas flow in low flow conditions. Pressure control failures could cause the unplanned release of natural gas, a pipeline rupture or over-pressure delivery to customers. The impact and frequency of a pressure control failure varies - the frequency of a pressure control failure causing a minor impact, such as a repair, is higher than the frequency of over-pressure delivery to a customer due to the multiple layers of protection within the gas distribution network.
- **Loss of Containment (Leaks)**: A leak is an unplanned release of gas from the gas distribution system. The risk of a leak leading to a fire or explosion has the potential to cause injury to members of the public. The risk of an over-pressure event at the station could similarly lead to a leak in the downstream system, including inside the customer's premises if other safeguards fail. Financial loss is possible due to total repair costs, commodity loss, relighting customer gas appliances and any property damages caused by a gas leak. Risks identified are potential GHG emissions, environmental impact, service interruptions, over- or under-pressure events and reputational damages associated with reduced public confidence.
- **Under-pressure Event**: In an under-pressure event, the downstream network is operating below the designed minimum pressure. See **Section 5.3.5.3** for risks associated with under-pressure events.
- **Valve System Malfunction**: A valve malfunctions when it no longer provides isolation of the gas as intended. See **Section 5.3.5.3** for risks associated with valve system malfunctions.

Additional issues that were considered in the risk assessments were obsolete regulators, single-run stations and stations with non-compliance issues. When obsolete regulators fail, they cannot be easily replaced as the existing station configuration may not have replacement parts available. When this occurs, the station must be replaced in its entirety, leading to a disruption in service and gas delivery impact. Single-run configurations are stations without a standby run available. A standby run can take over control to provide the required capacity and pressure of gas to a system in the event that maintenance of the station is required. Exposure to under-pressure risk is greater in the absence of a standby run. Non-compliant stations are typically locations where surrounding developments have encroached within the hazardous zone, causing clearance concerns.

Distribution system stations that are installed below-grade in a vault were evaluated to consider risks such as additional maintenance requirements, increased replacement cost and potential for worker injury. It is expected that the projected reliability for these below-ground assets will be lower and will degrade faster than other above-ground assets.

5.3.6.4. Strategy Outcomes

The renewal strategies for assets in the Distribution System Stations subclass support proactive replacements targeting stations based on obsolescence, condition and age:

Distribution System Station Replacement Strategy

This strategy mitigates risks associated with station condition and legacy station designs. Risks can be significant; one station may supply gas to hundreds of customers, and accordingly, all downstream mains and services can be affected by a failure. Stations are identified through regular inspections, information collection and condition methodology. This strategy will maintain the station population's current average condition and operational reliability, ensure operational capacity to meet current demands and minimize process safety risk. The program targets stations with the following issues:

- Below-ground boxes
- Boot-style regulators
- Capacity issues
- Poor performance and poor condition

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- Low pressure control
- Obsolete components

Condition assessment reviews, Subject Matter Advisor (SMA) consultation and risk assessments are all used to prioritize stations for replacement. Since these stations are small and pre-fabricated off site, the scope of the investment includes replacing the entire station (pressure control, overpressure protection, valves) and as necessary, associated inlet and outlet piping below ground.

The replacement pace for distribution system stations is approximately 20 to 30 stations per year in the EGD rate zone. This pace is aligned with the historical replacement rate. Models indicate this pace will maintain the reliability of the station population at a relatively consistent level over the next 20 years. This aligns with the feedback from the 2020 Customer Engagement Survey on replacing pipelines and equipment as the majority of customers indicated a preference for EGI to assess long-term system health system and to spread out costs over time (even if that means higher rates now). **Figure 5.3-10**: 20-Year illustrates the projected failure events of the population by maintaining the current replacement rate.

In the Union rate zones, condition assessments and operational issues are also used to identify stations for replacement - a programmatic approach that includes analysis will be developed to address the needs of these assets going forward.

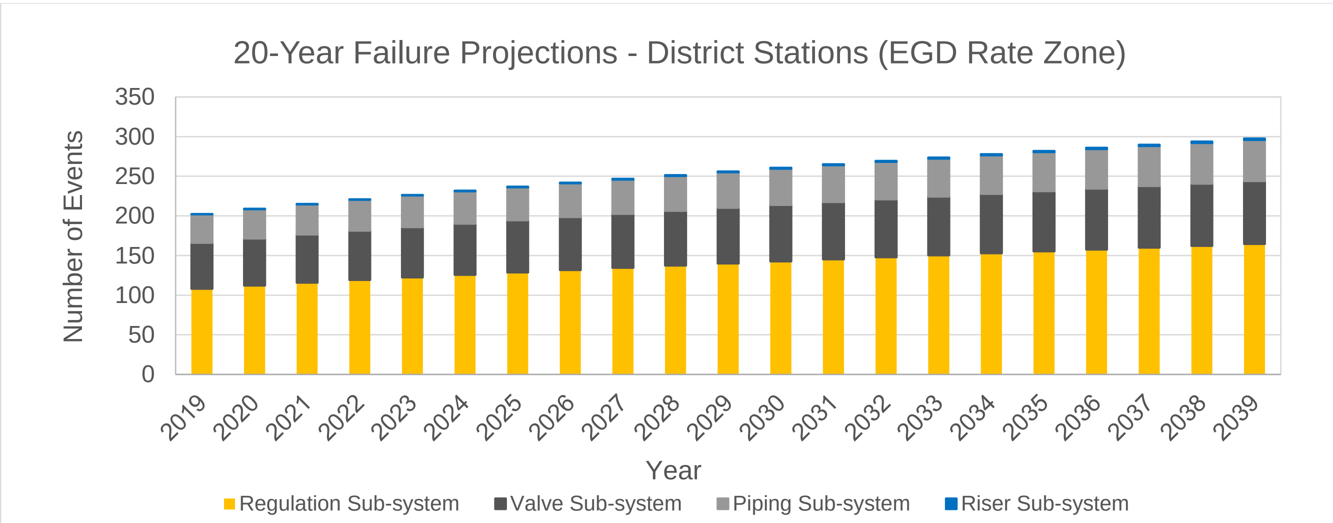

Figure 5.3-10: 20-Year Failure Projections – District Stations (EGD Rate Zone)

Header Station Replacement Program

This strategy targets header stations that require replacement due to the following issues: unsafe installation locations, poorly performing components, poor condition, obsolete components, non-standard configurations and other issues identified in **Section 5.3.6.2**. Stations are evaluated to validate downstream customer impact, asset condition and workers' health and safety to ensure maximum risk reduction and benefit for each replacement.

For the EGD rate zone, the strategy for header stations is to replace approximately 25 header stations per year, based on condition assessments, component age and obsolescence. **Figure 5.3-11** illustrates the projected failure events of the population by maintaining the current replacement rate.

Header stations in the Union rate zones are covered under the **Distribution System Station Replacement Strategy**.

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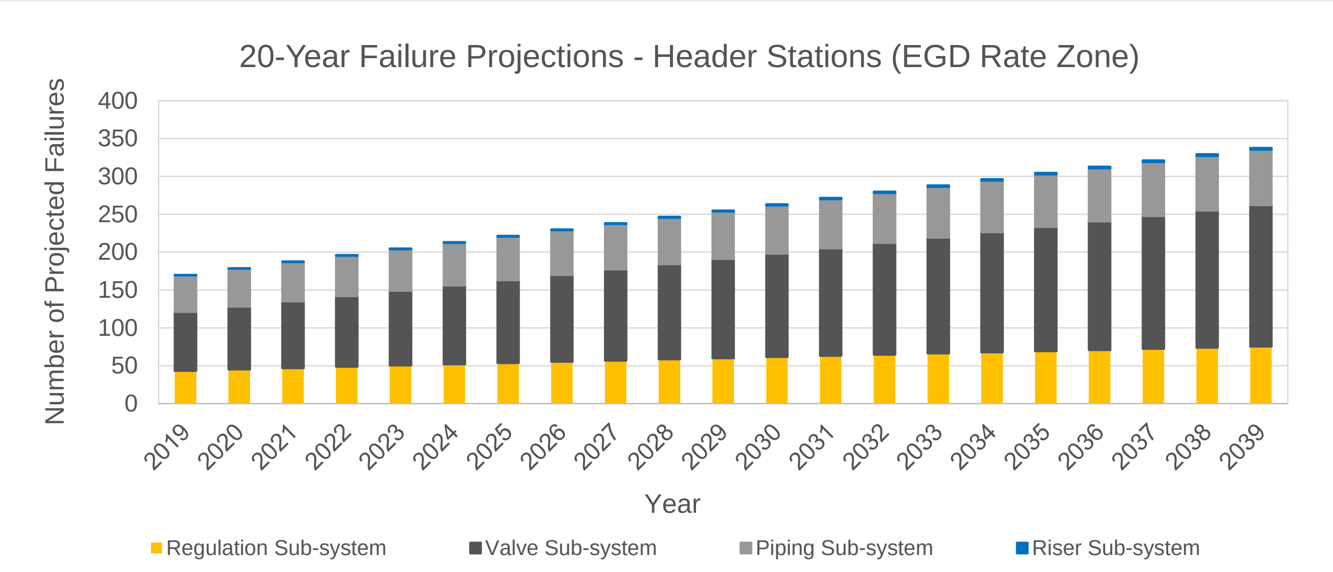

Figure 5.3-11: 20-Year Failure Projections - Header Stations (EGD Rate Zone)

Vaulted Stations Replacement Program

This program targets a subset of distribution system stations installed in below-grade vaults. The scope of this program includes replacing all remaining vaulted stations with above-grade facilities, reducing the risk of equipment failure. These stations are advanced in age and present significant maintenance challenges due to their confined nature and risks related to asset deterioration and equipment failure. The vault design is prone to water ingress that can cause frost heave, accelerated corrosion of assets and of the vault itself and can interfere with the proper equipment operation. All of these factors have a negative effect on reliability and worker safety. Solutions for each asset are developed considering either a typical system station design with land purchase or an above-grade enclosure station if land purchase is impractical. This program will decrease the risk of equipment failure, improve system reliability and result in stations being more safely and efficiently maintained.

Stations Painting Program

This program is a centrally-managed initiative to apply high-performance paint to mitigate corrosion of station assets. This program targets stations where existing paint has begun to fail or wear off, ensuring the safety and reliability of stations by reducing the probability of leaks and piping/equipment failure due to significant corrosion. This program is specific to the Union rate zones only.

Stations Capital Upgrade Program

See **Section 5.3.5.4** > **Stations Capital Upgrade Program**.

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5.3.7 Customer Stations

Customer stations reduce upstream pressure and deliver gas to a downstream customer with a total connected load greater than 12 m³/hour and with a delivery pressure of 14 kPa or greater (with a limited number of exceptions). Customer pressure and volume requirements are driven by their natural-gas-fired equipment requirements. Typical delivery pressures can vary up to 1,380 kPa or higher depending on individual customer needs. The estimated life expectancy for customer stations is shown in **Table 5.3-7**.

Typical components of customer stations can vary greatly based on customer delivery requirements (e.g. gas volume, delivery pressure). The smallest customer stations are typically comprised of small diameter piping, a single regulator, meter and shut-off valve. Larger customer stations can be comprised of multiple regulators and meters, large-diameter piping and headers, an electrical system, controls and telemetry and multiple valves. EGI's largest in-franchise customer station facilities typically supply natural gas to major electric power producers, major steel mills, chemical plants, smelters and other process-based industrial plants. Note that all customer stations that have filters/strainers, odourant and heating equipment are considered part of the Stations with Auxiliary Equipment asset subclass (see **Section 5.3.5**).

Table 5.3-7: Estimated Life Expectancy for Customer Stations

Rate Zone	Expected Life (SMA Input)	Average Asset Age (Years)	Max. Asset Age (Years)
EGD Rate Zone	25 to 38	17	59
Union Rate Zones	27 to 37	16	62

Although age is not the only factor in evaluating station asset conditions, an increase in failure is seen as the asset approaches the end of its useful life. **Figure 5.3-12** displays the age demographics in the EGD rate zone for the customer stations population.

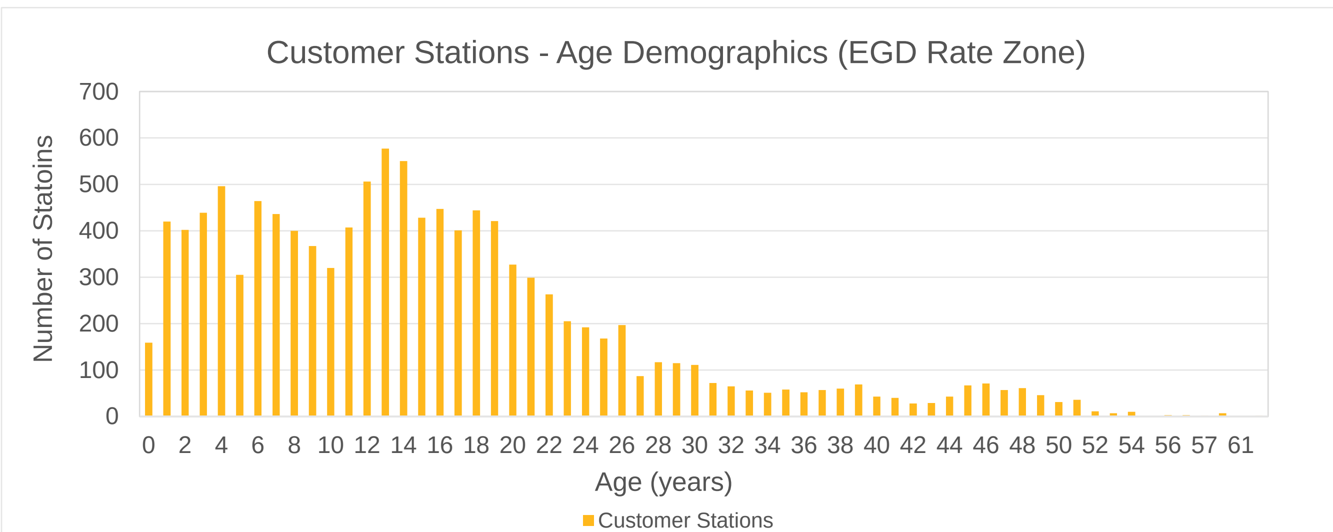

Figure 5.3-12: Customer Stations - Age Demographics (EGD Rate Zone)

Figure 5.3-13 displays the population age demographics for customer stations in the Union rate zones. An outlier in the number of stations at 30 years can be attributed to the integration of legacy asset information systems. The age data represents when the last asset was installed and may not reflect situations where existing assets remained within the station (i.e. pipe or valves that typically have longer lives). As systems and asset management practices are further aligned, data and analytics will become more consistent for the rate zones.

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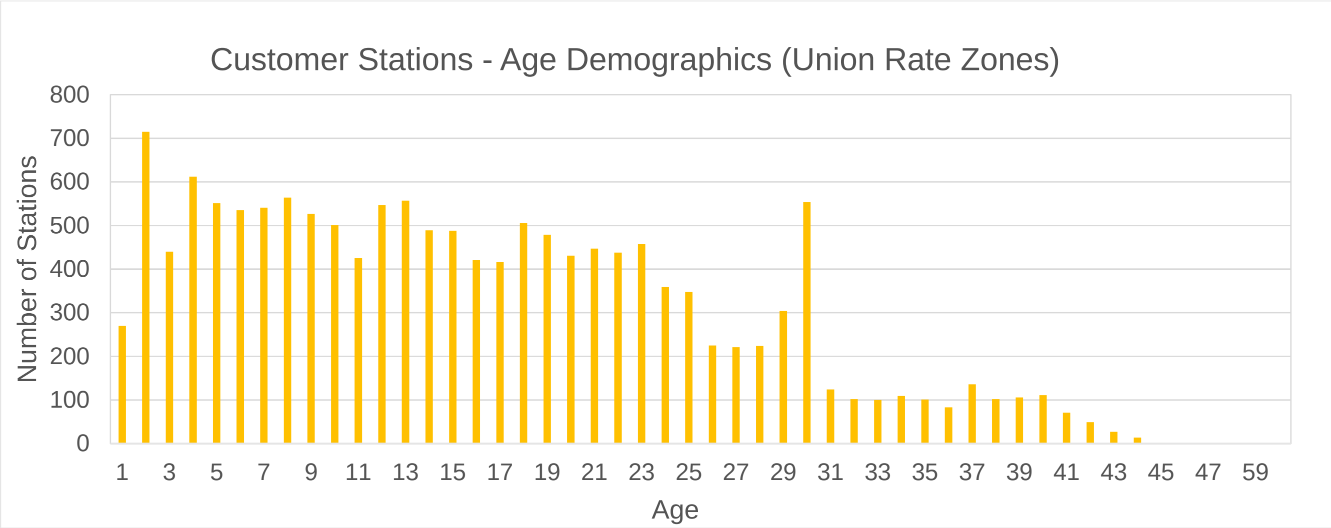

Figure 5.3-13: Customer Stations - Age Demographics (Union Rate Zones)

5.3.7.1. Condition Methodology

The condition methodology for customer stations is the same as for distribution system stations (see **Section 5.3.6.1**).

5.3.7.2. Condition Findings

Customer stations experience failures similar to distribution system stations (see **Section 5.3.6**).

As assets degrade over time, they typically begin to fail at an increasing rate and the accumulation of those failures over time will begin to account for a greater proportion of the total population. Using historical failure event rates to model the projected failure events, **Figure 5.3-14** helps to illustrate this relationship over time and provides useful insight into the impact of projected future failure events on customer stations with the current replacement program applied.

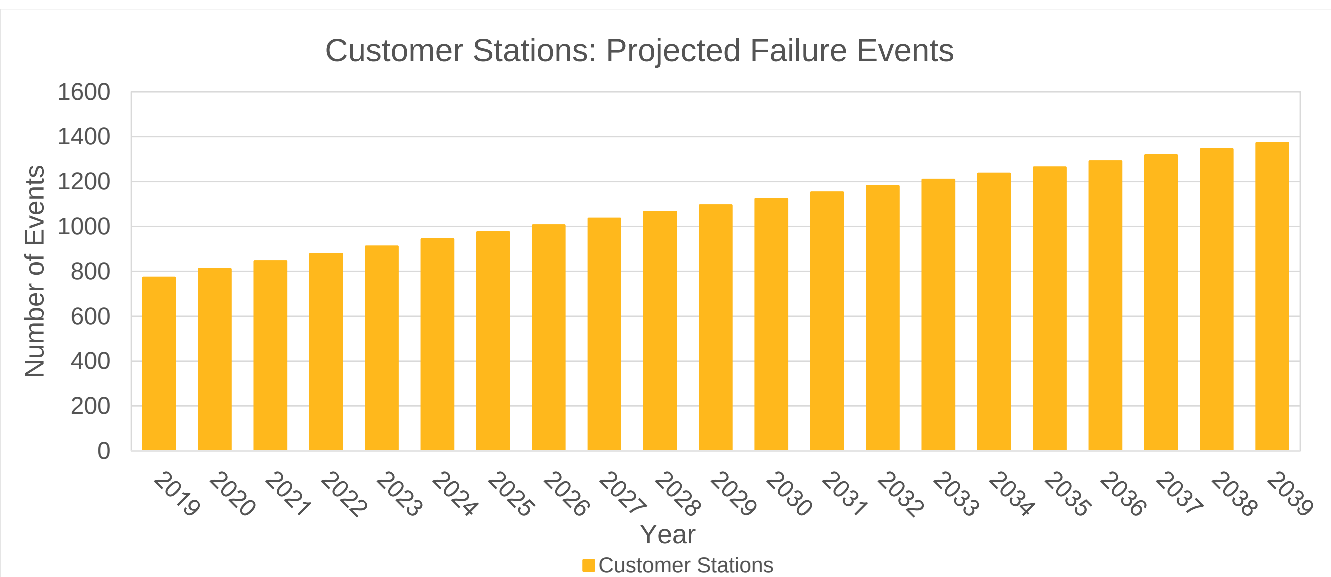

Figure 5.3-14: Customer Stations: Projected Failure Events

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Figure 5.3-14 illustrates that customer stations are forecasted to have a slight increase in failure events with the current replacement pace over a 20-year projection.

5.3.7.3. Risk and Opportunity

The risks identified for the Customer Stations asset class are similar to risks for distribution system stations (see **Section 5.3.6.3**) The hazards identified include:

- Over-pressure of non-boot style regulators
- Non-conforming station configurations
- Stations with compliance related issues
- Stations experiencing loss of containment (leaks)

The risk assessment on these conditions determines the potential failure of the asset: pressure control failure, valve system malfunction and loss of containment (leaks), discussed in **Section 5.3.6.3**.

Customer stations are the final pressure control point prior to entering into a customer's building. Leaks or loss of containment at a customer station can lead to an explosion or fire. Some factors included in this risk category are damage to property, injuries to members of the public and the cost to repair the damaged assets.

Another concern with a subset of these assets is the design or configuration of some customer stations, which does not allow for required maintenance work (compliance work) to be completed without customer interruptions.

5.3.7.4. Strategy Outcomes

The strategy for the Customer Stations asset subclass support proactive replacements targeting stations based on obsolescence, condition and age:

Customer Station Replacement Program

This program targets stations that have issues and concerns identified through regular inspections and will be based on condition, age and obsolescence. Issues targeted include non-standard configuration, unsafe installation locations, poor performing components, poor condition and obsolete components. Execution of this program will maintain reliable gas supply to customers, address sites with non-conforming configurations (i.e. legacy designs) and minimize impacts to businesses and customers.

Condition assessment reviews, SMA consultation, AHR projections and risk assessments are used to prioritize stations for replacement. Since these stations are small and pre-fabricated off site, the scope of the investment includes replacing the entire station (pressure control, overpressure protection, valves) and as necessary, associated inlet/outlet piping below ground. Customer stations are the direct supply and control to commercial and industrial customers and the consequence of a station failure can be significant. Prior to replacement, all stations are evaluated to validate customer impact, asset condition and worker health & safety to ensure maximum risk reduction and benefit.

Figure 5.3-15 illustrates the projected failure events of the customer station population in the EGD rate zone by maintaining the current condition and reliability of existing station assets. Analysis suggests customer stations failure events are projected to increase slightly over time with the historical replacement strategy in place.

Based on the historical replacement rate of the customer station population and comparing to the condition assessment findings, it is expected that the replacement rate should increase as part of the Asset Management Plan.

Customer stations in the Union rate zones are replaced based on condition and operational issues. As systems and asset management practices are further aligned, data and analytics will become more consistent for the rate zones.

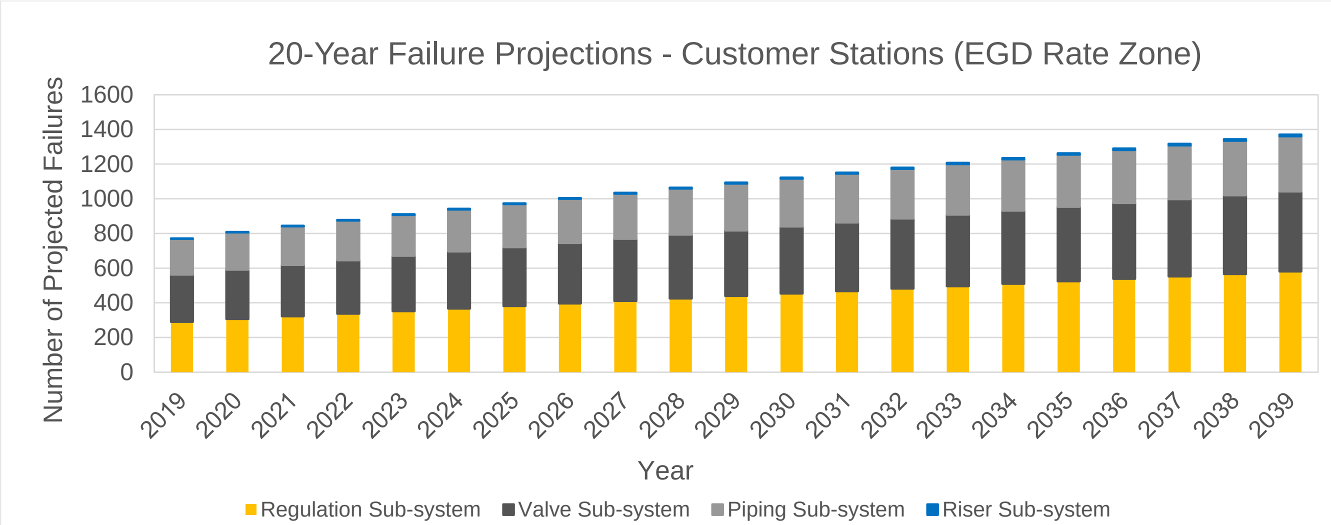

Figure 5.3-15: 20-Year Failure Projections – Customer Stations (EGD Rate Zone)

The conditions and risks associated with customer stations assets continue to be monitored and assessed to determine if the current replacement rate is adequate in maintaining the operational reliability and risks associated with these assets.

External Regulator Room Program

This program aims to reduce the risks associated with the installation of pressure-reducing regulators inside a building by relocating the regulator to a lower-risk location (at the exterior of the building envelope). An external regulator room is an enclosed room with adequate ventilation that has not been specifically designed and approved to house EGI regulators or stations. The scope of work involves remediating the room enclosure to ensure adequate ventilation to the exterior and to modify enclosing walls to be air-sealed from the building to prevent gas migration. This program is specific to the EGD rate zone only. A review of Union rate zone assets that are considered as inside regulators is ongoing and may have capital requirements in future years.

Stations Painting Program

See **Section 5.3.6.4** > **Stations Painting Program**

Stations Capital Upgrade Program

See **Section 5.3.6.4 > Stations Capital Upgrade Program**

5.3.8 Distribution Stations Capital Expenditure Summary

EGI has spent an average of $26M and $15M annually in the EGD and Union rate zones respectively for the Distribution Stations asset class. The total average capital spend is forecasted to be $42M (EGD RZ) and $30M (Union RZ) as summarized in **Table 5.3-8** and **Table 5.3-9**. Distribution Stations capital is further summarized as part of EGD's total 10-year capital plan in **Section 6.**

Table 5.3-8: Distribution Stations Capital Summary ($ Thousands) – EGD Rate Zone

Program/Project Name	2021	2022	2023	2024	2025	Five-Year Forecast
Compressed Natural Gas (CNG)	**1,135**	**1,255**	**926**	**914**	**988**	**5,218**
Stations with Auxiliary Equipment Replacement	**22,918**	**21,193**	**21,941**	**20,336**	**19,025**	**105,412**
Compliance Remediation Program	244	243	256	249	264	1,257
Telemetry Program	1,709	1,703	1,795	1,743	1,851	8,800
Inside Regulator and ERR Program	**610**	**608**	**641**	**622**	**661**	**3,143**
Distribution System Station Replacement	**15,926**	**27,730**	**15,195**	**13,860**	**16,482**	**89,192**
Harmer District Station	-	15,909	-	-	-	15,909
Stations Capital Upgrade Program	7,212	11,261	11,356	11,849	13,969	55,649
Integrity Initiatives	**1,416**	**1,411**	**1,487**	**1,444**	**1,533**	**7,292**
FIMP Inspections	1,416	1,411	1,487	1,444	1,533	7,292
EGD Rate Zone Total	**42,077**	**52,197**	**40,190**	**37,176**	**38,689**	**210,329**

Table 5.3-9: Distribution Stations Capital Summary ($ Thousands) – Union Rate Zones

Program/Project Name	2021	2022	2023	2024	2025	Five-Year Forecast
Compressed Natural Gas (CNG)	917	913	963	-	-	2,793
Stations with Auxiliary Equipment Replacement	**23,223**	**23,207**	**4,893**	**2,514**	**2,668**	**56,505**
Telemetry Program	3,729	3,043	2,568	2,514	2,668	14,522
Stations Capital Upgrade Program	19,493	20,164	2,325	-	-	41,983
Distribution System Station Replacement	**22,795**	**16,395**	**14,931**	**8,580**	**6,988**	**69,688**
Odorization System Program	1,234	1,228	1,118	1,095	1,162	5,837
Station Painting Program	2,446	2,434	2,568	2,514	2,668	12,630
Integrity Initiatives	**5,346**	**4,223**	**4,455**	**4,362**	**4,629**	**23,015**
FIMP Inspections	4,243	4,223	4,455	4,362	4,629	21,912
Union Rate Zones Total	**52,280**	**44,737**	**25,242**	**15,456**	**14,285**	**152,001**

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5.4 Utilization

Utilization assets are the components of the distribution system that regulate system pressure, ensure low pressure delivery to the customer and measure gas consumption. Safety is the paramount role of these assets, as the regulation system within it is the last line of defense for over-pressure to the customer. Unlike customer stations described in **Section 5.3.7**, these assets support the delivery of gas primarily to customers consuming volumes less than 17.0 m³/h at a typical pressures of 7"wc.

Each Utilization asset subclass has unique characteristics and the management of each is tailored to ensure the safe and reliable delivery of natural gas. Utilization is comprised of three asset subclasses–measurement systems, pressure regulation and over-protection systems and below-ground and internal piping systems.

5.4.1 Utilization Objectives

The objectives for the Utilization asset class are listed in **Table 5.4-1**.

Table 5.4-1: Utilization Asset Class Objectives

Asset Class Objective	
System Integrity and Reliability	Maintain the natural gas system to meet or exceed codes, standards and requirements of applicable governmental authorities for safety and operational effectiveness. This includes ensuring the system has the capacity to reliably meet current and future customer demand.
	Ensure the safe and reliable delivery of natural gas to end users.
	Use cost, risk and performance information to drive asset-related decisions.
	Continuously evolve the understanding of condition and risk associated with Utilization assets.
	Ensure accurate metering of customer gas consumption.

The performance measures for the Utilization asset class are:

- Completion of Government Inspection Meter Exchange (MXGI) program
- Percentage of failed meters within sampling program
- Number of doubtful meters (EGD rate zone only)
- Number of above-ground leaks
- Number of non-program failures and explanations
- Work management process conformance

To achieve the Utilization asset class objectives listed in **Table 5.4-1**, asset investment decisions are governed by the life cycle management strategies outlined in **Table 4.1-1**.

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5.4.2 Utilization Hierarchy

The asset class hierarchy for the Utilization asset class is summarized in **Figure 5.4-1**.

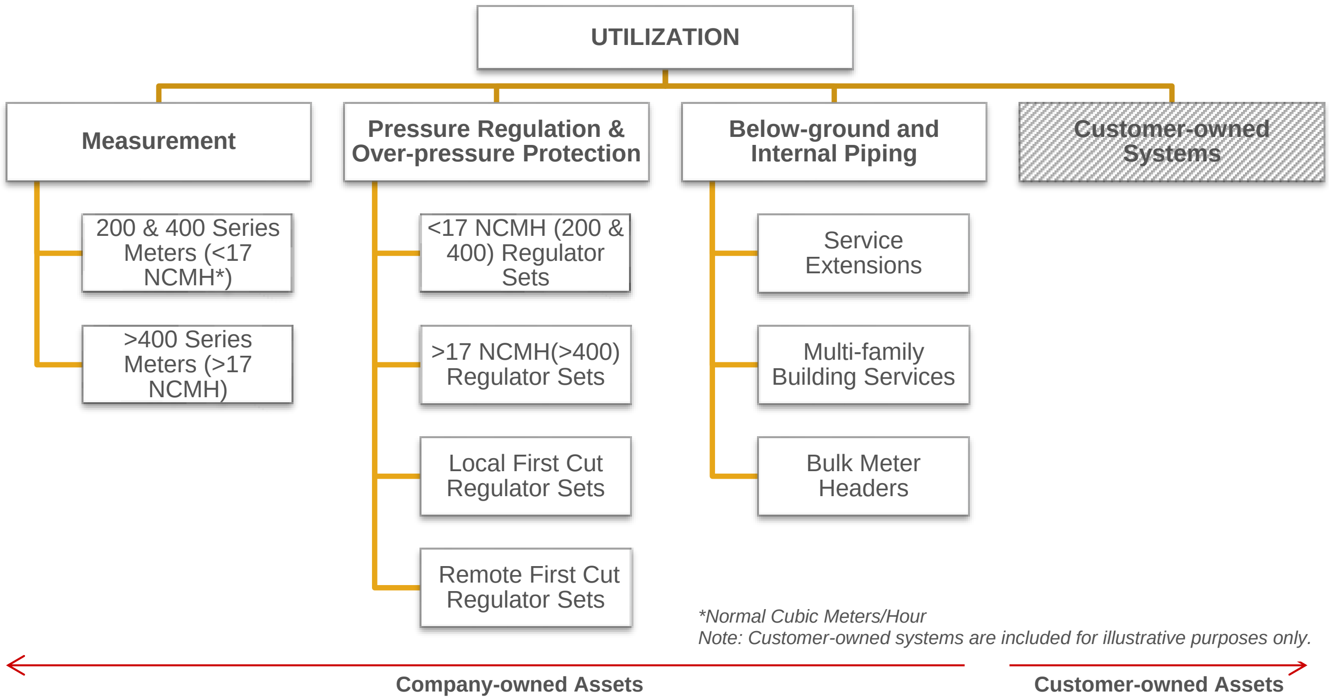

Figure 5.4-1: Utilization Asset Class Hierarchy

Measurement Systems (natural gas meters and electronic volume correctors (EVCs)) track customer gas consumption. These systems directly link to customer billing and are subject to a stringent replacement program overseen by Measurement Canada. Measurement assets allow the safe operation of the natural gas network, provide accurate and timely measurement and monitor and control the flow of natural gas in real time.

Natural Gas Meters are devices used in measuring the quantity of natural gas delivered. Meters are classified as custody transfer or non-custody transfer. The former are billing meters for gas purchased from suppliers or sold to customers and must meet the legal requirements of the *Electricity and Gas Inspection Act*. The latter are used for internal accounting of gas inventories. EGI uses a variety of gas meter types to fit different applications and requirements:

- **Diaphragm meters** use positive displacement technology and internal mechanical temperature compensation to calculate delivered natural gas volumes at base temperature and pressure. The 200 series meter is the most common meter type in use. The 400 series meters are used for commercial and large residential loads and have incrementally more capacity than a 200 series meter. The 800/1000 series meters are used for large commercial, small industrial and estate residential loads.
- **Commercial ultrasonic meters** are used as a direct substitute for 800/1000 series diaphragm meters. These meters use inferential ultrasonic flow measurement, electronic temperature correction and consumption recording.
- **Rotary meters** are positive displacement devices comprised of a meter body with an EVC and are used in commercial and industrial applications.
- **Large turbine meters** are inferential metering devices used at large commercial and industrial customer stations for high-volume metering. They are also used for volumetric measurement at interconnect sites between EGI and other pipeline companies.
- **Large ultrasonic meters** are sophisticated multi-path inferential measurement devices directly connected to remote terminal units (RTUs) for measurement of large volumes of gas at high pressures.

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Electronic Volume Correctors (**EVC**) typically receive volume measurement inputs from a meter. EVCs measure the temperature and pressure and corrects the measured volume for both. EVCs store measurement information and are capable of doing detailed calculations, if provided with various factors, to give a corrected volume.

Pressure Regulation and Over-pressure Protection Systems regulate the delivery of gas at a pressure appropriate for customer-owned gas-firing appliances and are the last line of defense for over-pressure protection. Three typical safety devices used in the Utilization asset class–internal relief valves, external relief valves and over-pressure cut-offs.

With the exception of customers off low pressure mains, each customer location has at least one regulator and one over-pressure safety device installed to prevent unsafe pressures from entering the premises in the event of a malfunction. These systems include above-ground piping between the wing-lock and meter and the components required for regulation.

This asset subclass is comprised of the following components:

- **Regulators** reduce natural gas pressure to safe operating limits and control its flow based on customer demand. Regulators typically have an internal relief valve designed to be closed but will open if the primary regulation function is malfunctioning. Regulators in the Utilization asset class are regulated to deliver low pressure, typically at 7" wc.
- **Safety devices** prevent downstream over-pressure and are the last line of defense to prevent potentially hazardous conditions.
- **Piping on regulator sets** refers to any of the above-ground piping between the winglock and the meter outlet.

Below-ground and Internal Piping Systems: These systems are located upstream of inside meters and refer to piping running below grade or piping running inside a building.

EGI owns a type of below-ground asset called a service extension. Service extensions are below-ground pipe between the regulator outlet and the meter inlet (not to be confused with jumpers owned by the customer since they are downstream of the meter set). Within this asset class, EGI takes all reasonable efforts to avoid below-ground piping since this type of configuration has inherent hazards and requires costly maintenance. Internal piping is typically found in multi-family buildings. This piping runs between the regulation and piping system located outside to meters inside the garage or in individual units.

Customer-owned Systems: Piping and assets downstream of the meter are customer-owned. Although EGI does not own these assets, *O. Reg. 212/01* requires an inspection of all installations upon initial connection to the gas supply or during the reintroduction of gas. In addition, EGI continues to inspect customer assets as part of a quality management program. By meeting these requirements, EGI helps to ensure the safe delivery of natural gas. As a last resort, EGI can terminate the natural gas supply if the customer fails to remediate any identified critical safety issues. As customer-owned systems are not part of EGI's assets, they are included in this discussion for illustrative purposes only (see **Figure 5.4-2**).

Figure 5.4-2: Utilization Assets Illustration

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5.4.3 Utilization Inventory

Utilization assets include all assets downstream of the wing-lock valve and upstream of the meter outlet. These assets serve customers grouped into the following categories based on similar characteristics:

- Multi-family/Apartment
- Commercial/Bulk Meter
- Industrial
- Residential (low density)

Over 90% of customers are residential, with the remaining being mostly commercial. With 2.2 million customers in the EGD rate zone and 1.5 million customers in the Union rate zones requiring low pressure delivery, understanding and maintaining the health of these assets is a critical part of providing safe and reliable gas delivery.

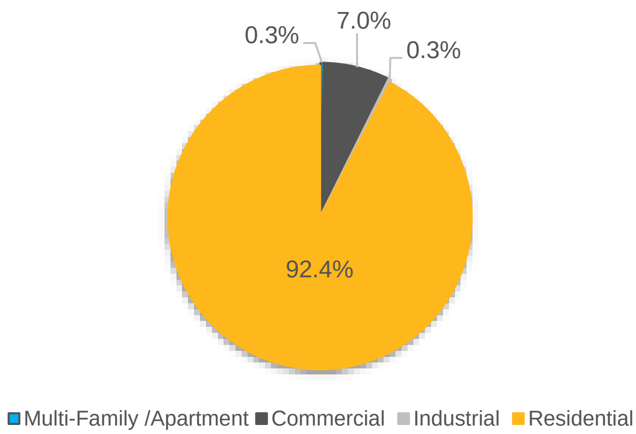

Figure 5.4-3: Customer Breakdown by Type – EGD Rate Zone

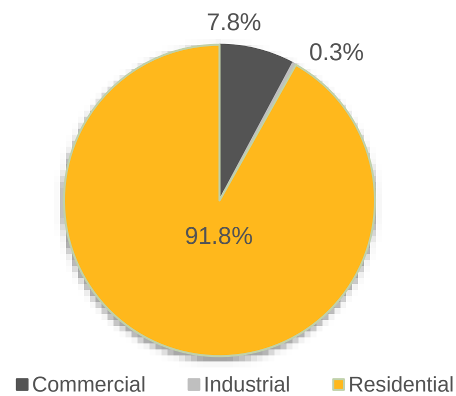

Figure 5.4-4: Customer Breakdown by Type – Union Rate Zones

For the Union rate zones, efforts are underway to recategorize multi-family/apartment customer data to align customer classifications as part of integration activities.

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Table 5.4-2 lists the inventory details for the Utilization asset class.

Table 5.4-2: Utilization Asset Class Inventory

Asset Subclass	EGD Rate Zone	Union Rate Zones
Measurement Systems		
200 and 400 Series Meters (<17 NCMH*)	2,190,131	1,463,833
>400 Series Meters (>17 NCMH)	65,999	24,658
Regulation, Safety Devices and Piping Systems		
<17 NCMH (200 and 400) Regulator Sets	1,986,323	1,012,464
>17 NCMH (>400) Regulator Sets	103,566	42,475
Local First Cut Regulator Sets	25,964	N/A
Remote First Cut Regulator Sets	10,495	N/A
Below-ground And Internal Piping Systems		
Service Extensions	13,666	N/A
Multi-Family Building Services	3,002	N/A
Bulk Meter Headers	39	N/A

***Normal Cubic Meters/Hour*

The number of meters and regulators in the EGD rate zone includes those at customer stations (excluded in the Union rate zones).

For the Union rate zones, inventories for local first cut regulator sets, remote first cut regulator sets and below-ground and internal piping systems are not currently available. As part of integration activities, inventory tracking processes will be harmonized over time.

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5.4.4 Utilization Condition and Strategy Overview

Asset Subclass	Avg. Age (Year)	Condition	Risk / Opportunity	Maintenance Strategy	Replacement / Renewal Strategy
Measurement Systems **200 and 400 Series Meters (<17 NCMH)** **>400 Series Meters (>17 NCMH)**	Dependent on meter type. Between: • 18-24 years old • 10-20 years old	Meter Exchange Government Inspection (MXGI) Program: This program is designed to replace meters before they fail. Meter seal life (and extensions) is based on sampling and testing to ensure Measurement Canada specifications are maintained. Non-program: Non-program meters that fail before the prescribed maximum service life are discovered during emergency calls or customer-initiated work. In most years, the number of meters exchanged outside of the program represents less than 1% of the population.	Failing to remove failed meters from service carries penalties under the *Electricity and Gas Inspection Act*, leading to: **Financial Risk**: Monetary penalty for non-compliance to government mandated programs. Monetary loss due to shortened life cycle of meters, related to accreditation loss. In addition, there is a financial opportunity to remove groups of meters that have been sampled multiple times with the availability of short extensions remaining.	The maintenance strategy for measurement assets is to continue with current maintenance standards at each rate zone until procedures and standards are aligned, targeted over the next two years. The joint Measurement Canada meter shop accreditation for both rate zones is targeted for 2022. Reactive maintenance – based on operating standards is on an as-needed basis to address customer leaks and/or emergency calls. Complete maintenance and inspections through operating standards.	The renewal strategy for measurement assets are as follows: For 200, 400 and >400 series meters covered under the MXGI program, the renewal strategy is to follow approved Measurement Canada programs. For >1000 series meters, meter exchanges are conducted one year prior to expiry as there is no sampling program in place. EGI reactively responds to customer leak or other service interruption calls for non-program related meter exchanges. In addition, EGI continues to use data to project MXGI replacement volumes with a focus on leveling volumes over future years. Meters have a complete set of data that includes quantity, age, make, size, location and historical performance. The completeness of this data enhances the optimization of the life cycle strategy.
Regulation, Safety and Piping Systems **<17 NCMH (200 and 400) Regulator Sets**	Dependent on meter and regulator type: between 20-30 years old. (~16% of the population is over 20 years old.)	Failure history and trending indicates that the wear-out phase for regulators associated with 200 and 400 series meters is unlikely to occur before 30 years of age. The failure rate is 0.14% of total population.	Majority of customers are connected to the distribution system through 200 and 400 series regulator sets. Not maintaining these assets can lead to: **Employee and Contractor Safety Risk and Public Safety Risk**: Loss of containment, threat to over-pressuring customer piping, possibly leading to explosion **Financial Risk**: Repair, commodity loss, relights, potential property damage costs Failure of these assets primarily exposes EGI to financial risk.	The maintenance strategy for 200 and 400 series regulator sets is to proactively maintain units in conjunction with EGI's MXGI program. Reactive maintenance is on an as-needed basis (based on operating standards) to address customer leaks and/or emergency calls. Note: EGI's MXGI Program, which covers all variations of meters and regulators, adheres to Measurement Canada requirements.	EGI's proactive replacement/renewal strategy for replacing 200 and 400 series regulator sets is to proactively exchange regulators as part of the MXGI program. Exchanging regulators during MXGI inspections prevents the population from reaching the wear-out phase. Run-to-failure is not an acceptable policy for this asset, as regulators are the last line of defense for over-pressure to the customer. Other compliance issues are corrected as part of MXGI work. 200 and 400 series regulator sets are opportunistically replaced if found to be 20 years or older.
Regulation, Safety and Piping Systems: **>17 NCMH (>400) Regulator Sets**	Dependent on meter and regulator type: between 20-30 years old.	>400 series regulator sets have an older population compared to 200 and 400 series regulator sets. For the EGD rate zone, more than half of these regulator sets have regulators older than 20 years. A sample survey identified sites not adhering to current installation specifications.	>400 series regulator sets account for 4.6% of all EGI regulator sets and are predominantly used in commercial, industrial, or higher density residential premises. The risks identified for >400 series regulator sets are the same as 200 and 400 series regulator sets. However, since delivery rates for > 400 series regulator sets are higher than delivery rates for the 200 and 400 series, the consequences are potentially greater and put a higher number of end users at risk.	The maintenance strategy for >400 series regulator sets is to adhere to a proactive and targeted inspection and remediation program, ensuring installation meets current code requirements in EGI operating standards. Reactive maintenance is on an as-needed basis to address customer leaks and/or emergency calls.	The proactive replacement/renewal strategy for >400 series regulator sets is to replace assets older than 20 years through the MXGI program. The Distribution Integrity Management Program (DIMP) leverages data on failure modes and frequencies to inform future maintenance strategies. EGI's proactive replacement/renewal strategy for replacing >400 series regulator sets is through: **Targeted Inspection and Remediation Program**: Sites identified with specific issues through integrity surveys will be remediated to ensure regulator sets are brought up to current installation standards. Similar to 200 and 400 series regulator sets, >400 series regulator sets are opportunistically replaced if found to be 20 years or older.
Regulation, Safety and Piping Systems: **Local First Cut Regulator Sets**	Dependent on meter and regulator type: between 20-30 years old.	Local first cut regulator sets in the EGD rate zone were surveyed for corrosion. Failure history and trending indicate the wear-out phase for regulators associated with 200 and 400 series meters is unlikely to occur before 30 years of age. First cut regulators were not historically replaced at the same time as second cut regulators, as per current installation standards. Sites not compliant with installation specifications are remediated.	These assets account for a very small percentage of the total set population and present higher consequences due to higher pressures managed by two pressure cuts. The risks identified for local first cut regulator sets are the same as 200 and 400 series regulator sets. However, these assets present a higher consequence than traditional single cut regulator sets due to the higher pressures managed by two pressure cuts.	The maintenance strategy for local first cut regulator sets is to proactively maintain units in conjunction with EGI's MXGI program. Reactive maintenance is on an as-needed basis to address customer leaks and/or emergency calls.	EGI's proactive replacement/renewal strategy for replacing local first cut regulator sets is through: **Regulator Exchange Program**: Proactively exchanging regulators as part of the MXGI program prevents the population from reaching the wear-out phase (the first cut regulator must be exchanged if the second cut is exchanged). Run-to-failure is not an acceptable policy for this asset, as regulators are the last line of defense for over-pressure to the customer. Local first cut regulator sets are opportunistically replaced if found to be 20 years or older.

Asset Subclass	Avg. Age (Year)	Condition	Risk / Opportunity	Maintenance Strategy	Replacement / Renewal Strategy
Regulation, Safety and Piping Systems: **Remote First Cut Regulator Sets (Farm Taps)**	Dependent on meter and regulator type: between 20-30 years old.	Remote first cut regulator set sites older than 15 years were determined to have more significant condition issues. First cut regulators are installed away from premises and near the property line, making them more susceptible to corrosion and third party damage. First cut regulators were not historically replaced at the same time as second cut regulators.	These assets account for a very small percentage of the total regulator set population. These regulator sets present a higher consequence due to the high pressures managed by the two pressure cuts. The risks identified for remote first cut regulator sets are the same as 200 and 400 series regulator sets. Remote first cut regulator sets present higher risks than 200 and 400 series regulator sets due to the higher pressures managed by the regulator.	The maintenance strategy for remote first cut regulator sets is to proactively maintain units in conjunction with EGI's MXGI program. Reactive maintenance is on an as-needed basis based on EGI operating standards to address customer leaks and/or emergency calls. Remote first cut regulator sets are included in the survey cycle of the Leak Survey program. Complete maintenance and inspections are performed based on operating standards.	For the EGD rate zone, a survey of 1700 remote first cut regulator sets was completed in 2017 to provide knowledge of asset condition. A risk assessment will be completed in 2020 to determine mitigation strategies. The proactive replacement/renewal strategy for replacing remote first cut regulator sets is through: **Inspection and Remediation Program**: Continuation of comprehensive inspection program (including surveying all sites to categorize inventories) and remediating identified issues as required. **Regulator Exchange Program**: Proactively exchange regulators as part of the MXGI program. The first cut regulator must be exchanged if the second cut is exchanged. Run-to-failure is not an acceptable policy for this asset, as regulators are the last line of defense for over-pressure to the customer. Outside of MXGI work, regulators are replaced if found to be 20 years or older. For the Union rate zones, a 2020 survey of a sample remote first cut regulator sets is planned and will provide initial knowledge on the asset subclass condition. As part of integration activities, a Remote First Cut Regulator Set assessment program will be developed to better understand the condition of the broader population in both rate zones and to determine if further proactive processes or programs will be required to ensure safe and efficient operations.
Underground/Below-ground/Internal Piping Systems	N/A	**Service Extensions:** In the EGD rate zone, a sample survey of service extensions showed that some subsets have a population that requires cathodic protection. **Multi-Family Building Services:** In the EGD rate zone, EGI's Leak Survey program provides insight into the condition of multi-family building services assets. Generally, corrosion is found where the pipe intersects with the concrete wall–any severe corrosion that could affect safety is remediated. **Bulk Meter Headers:** EGI inspected bulk meter header sites in the EGD rate zone to understand condition and site factors. Common issues identified: • No clear demarcation points between EGI and customer assets • Obsolete regulators 20 years and older • Non-adherence to current installation and maintenance specifications • Vent clearances and configurations not met, not all fittings located above-ground and obsolete components A process to establish the population and determine condition will be aligned across the rate zones.	The risks identified are the same as 200 and 400 series regulator sets. • **Service Extensions**: since this piping enters the building below grade, gas leaks may have a higher chance of migration into the building, resulting in gas accumulation and a potential incident. • **Multi-Family Building Services**: since this piping system category is located inside high occupancy buildings, the potential consequence of failure is higher and a loss of containment will impact more people. • **Bulk Meter Headers**: since the building serviced are higher-occupancy units, there is potential for a higher consequence of failure. • The lack of clear demarcation between EGI and customer assets can further increase the risk of these headers. EGI is obtaining further information on these assets to better understand and manage asset risk.	The maintenance strategy for Underground/Below-ground/Internal Piping Systems assets is to continue to conduct Leak Survey and Cathodic Protection Survey programs based on operating standards through the DIMP. Reactive maintenance is on an as-needed basis to address customer leaks and/or emergency calls. Complete maintenance and inspections are performed based on operating standards.	EGI's replacement/renewal strategy for replacing service extensions is through: **Opportunistic Replacement**: Replace service extensions when the gas service is replaced and during planned city sidewalk/road replacements. **Continuation of Data Collection**: Sampling will be used to reassess risks and validate the feasibility of an above-ground inspection tool. EGI's replacement/renewal strategy for multi-family building services assets is through: **Replacement/Renewal**: Remediate high-priority condition issues identified through the Leak Survey and Cathodic Protection programs. For the EGD rate zone, EGI's replacement/renewal strategy for bulk meter headers is through: **Regulator Exchange Program**: Proactively exchange bulk meter headers as part of the MXGI program. **Delineation Definition**: Confirmation of a definitive delineation point between EGI and customer assets. All company-owned plant to be included in existing maintenance, replacement and renewal programs. **Inspection and Remediation Program**: Continuation of the targeted Leak Survey and Cathodic Protection programs. Outside of MXGI work, bulk header meters are replaced if found to be 20 years or older. The strategy for the Union rate zones will be determined following an inventory assessment of assets in this subclass.

Asset Subclass	Avg. Age (Year)	Condition	Risk / Opportunity	Maintenance Strategy	Replacement / Renewal Strategy
Customer Owned Systems: **Customer-owned Piping and Appliances**	N/A	EGI inspects customer-owned assets at the time of initial installation and after conducting relights. Customers are issued A-tags if unacceptable conditions that present an immediate hazard are identified.	Improperly identifying customer-owned assets for maintenance can lead to the following risks: **Employee and Contractor Safety Risk and Public Safety Risk**: Loss of containment **Financial Risk**: Emergency response costs	The maintenance strategy for customer-owned assets is to continue to perform existing operating standards at initial installation. Reactive maintenance is on an as-needed basis to address customer leaks and/or emergency calls.	The current strategy for customer-owned systems is to continue existing practices at initial installation. For any subsequent issues, the customer is responsible to take corrective action.

5.4.5 Measurement Systems

Meters represent the largest group of assets within the Utilization asset class. Meters measure gas flow to the customer premises. Different measurement devices are used to measure customer consumption:

200 and 400 Series Meters have a capacity 17.0 m^3/h or less. All meters in this subclass are diaphragm meters.

>400 Series Meters have a capacity 17.0 m^3/h or greater and can be comprised of the following meter types:

- Diaphragm meters
- Rotary meters
- Ultrasonic meters
- Turbine meters

Certain meters have instruments (electronic volume correctors) that perform compensation to accurately measure gas flow. Instruments are components of 800 series rotary meters and 800 series ultrasonic meters, used for environmental temperature and/or pressure compensation.

Meters are managed through a well-established program detailing the performance testing, repair and replacement requirements of meters and instruments. All verified meters are approved by Measurement Canada with an issuance of a certificate identifying the meter as compliant with *Electricity and Gas Specification S-EG-02*, which specifies meter tolerance. EGI must ensure all measurement devices remain in compliance for annual Measurement Canada audits and must demonstrate all aspects of its meter sampling, maintenance and replacement activities are compliant to receive Measurement Canada accreditation as an authorized service provider and to adhere to *Measurement Canada Accreditation Standard S-A-01*.

5.4.5.1. Condition Methodology

The replacement of the meter population is prescribed by Measurement Canada requirements and fulfilled by System Measurement programs. Government Inspection Meter Exchange (MXGI) volumes are driven by a sampling program. Based on the failure rate of sampled meter groups, groups are either given in-service extensions or are fully replaced, ensuring the health and accuracy of the asset. Groups of meters that have short seal life extensions available to them are also replaced. This approach optimizes sampling and meter group replacement costs, to stabilize workload and meter purchases as some years have larger populations to survey. Sample results and corresponding extension durations are used to indicate meter group health.

The methodology for determining meter replacement is developed by Measurement Canada and varies by meter type:

200 And 400 Series Meters (<17 NCMH): The pace and methodology of diaphragm meter replacements is set by Measurement Canada's *S-S-06 Standard Sampling Plans*. Annual sampling is carried out on meter groups. Meters are due for replacement originally based on their initial span (10 years for most 200 series meters, seven years for 400 series meters). Meters are grouped homogenously–in the year before first expiry (typically at Year 9 for 200 series meters), samples are pulled from each group for testing. If the sample meters pass, then a life extension of 8, 6, 4, or 2 years (based on the meters' initial span) is given to the meter group. If the sample meters fail (0), the meters are removed from service. Meter groups that pass require further testing after their next extended life span expires (i.e., 6, 4, or 2 years).

>400 Series Meters (>17 NCMH): Rotary meters, turbine meters and instruments (electronic volume correctors) do not qualify for sample inspection. The life cycle management for these meters is to renew and replace prior to seal expiry, as 100% of these assets are exchanged a year before their seal expires. Rotary meters expire after 16 to 20 years, ultrasonic meters at 10 years, turbine meters at six years and instruments at 7 to 12 years.

>1000 Series Meters: Meters are exchanged based on expiry year.

Exchanged meters are processed at the meter shops on EGI premises, as one of the facilities is accredited by Measurement Canada. Processing includes labelling, cleaning and performance testing. Meters are also sent offsite to accredited meter inspections facilities as required

In addition to the MXGI program, meters are also exchanged when malfunctioning, when customer load changes, or if involved in billing investigations.

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5.4.5.2. Condition Findings

The MXGI program is designed to keep the in-service meter population healthy. The length of extensions is dependent on sample group performance. In addition, the maximum achievable extension decreases as sampling of a group increases. For 200 and 400 series meters, the typical in-service life for meter groups is 18 to 24 years. As manufacturing and handling processes have evolved over time, meter groups frequently reach 24 years and beyond. The historical quantity of program-exchanged meters and non-program exchanged meters is shown in **Table 5.4-3**.

Table 5.4-3: Meter Replacements (Historical)

Year	MXGI Program Meter Exchanges	Non-Program Meter Exchanges	MXGI Program Meter Exchanges	Non-Program Meter Exchanges
	EGD Rate Zone		Union Rate Zones	
2016	63,425	17,222	54,900	12,501
2017	26,965	15,729	54,559	13,609
2018	46,651	17,796	55,603	13,240
2019	40,839	17,271	53,948	11,326

Non-program meter exchanges are attributed to the reasons listed in **Figure 5.4-5** and **Figure 5.4-6**. As reporting and analytics for the asset class are integrated, naming conventions will be aligned to clearly identify the reasons for the meter exchange, which will allow for maintenance strategies to be refined.
Meters exchanged due to leaks are low.

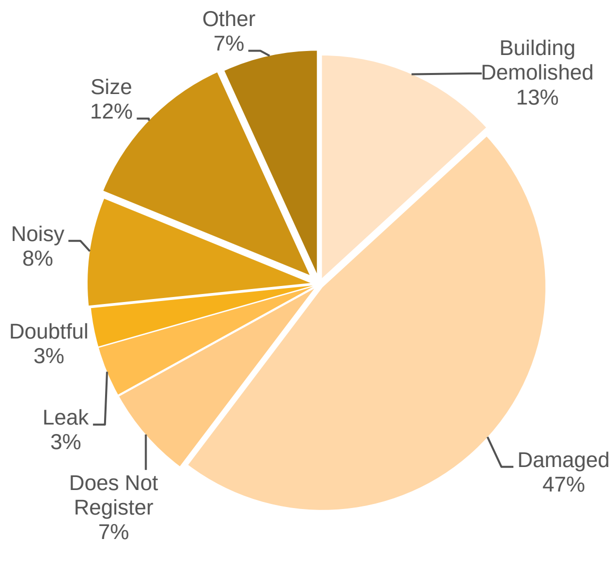

Figure 5.4-5: Causes of Non-Program Meter Exchanges (2017) – EGD Rate Zone

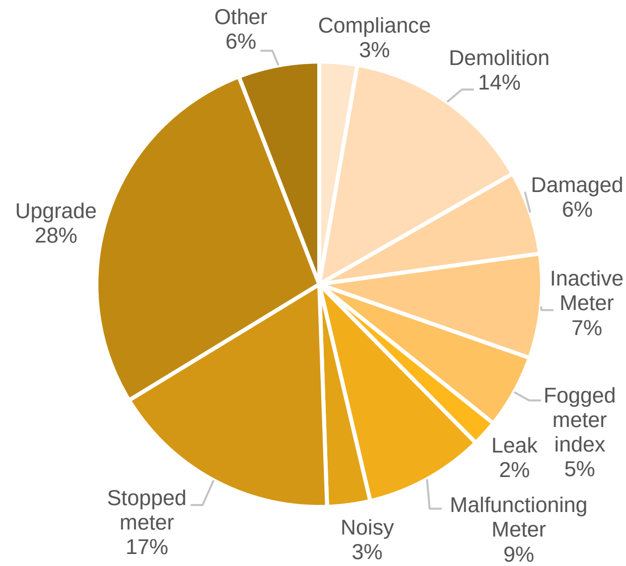

Figure 5.4-6: Causes of Non-Program Meter Exchanges (2019) – Union Rate Zones

5.4.5.3. Risk and Opportunity

MXGI Risk

Failing to remove expired meters from service carries penalties under the *Electricity and Gas Inspection Act*. Penalties could eventually lead to EGI's loss of accreditation, leading to higher meter replacement program costs. Therefore, maintaining Measurement Canada accreditation is critical for resealing meters, which allows for an extension to the life of meter assets that would otherwise need replacement. The financial risk would be a monetary penalty to EGI for not removing failed and overdue meters if the MXGI program was not executed, as well as the financial impacts of a reduced asset life cycle.

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Non-MXGI Program Meter Exchange Risk

Non-MXGI program meter exchanges target leaking meters, damaged meters and meters that do not flow gas. Hazards associated with leaks could result in migration and gas accumulation. However, the health and safety risk associated with meters is minimal, as meters leak very infrequently and majority are located outside customer premises. Very few meters are returned due to leaks (approximately 0.007% of the population annually). The financial risk of failed or leaking meters may lead to financial loss due to repair costs, relighting customer gas appliances and any property damages. As well, EGI may lose revenue from stopped meters. These risks can result in damage to the EGI brand which promotes the core values of safety and reliability.

In addition, there is a financial opportunity to remove groups of meters that have been sampled multiple times with the availability of short extensions remaining.

5.4.5.4. Strategy Outcomes

The maintenance strategy for these assets is to continue with current practices at each rate zone until procedures and processes are aligned, targeted over the next two years. The joint Measurement Canada accreditation for both rate zones is targeted for 2022.

The renewal strategy for measurement assets are as follows:

- For 200, 400 and >400 series meters covered under the MXGI program, the renewal strategy is to maintain current practices at each rate zone until policies are aligned (i.e., sampling vs. exchanging groups with only short extensions available).
- For >1000 series meters, meter exchanges will be conducted in the year of expiry or one year prior to expiry (if warranted) as there is no sampling program in place. The typical lifespan of >1000 series meters vary by type:
    - Rotary meters: 16-20 years
    - Modules: 10-12 years
    - Turbine meters: 6 years
    - Instruments: 7-12 years
- EGI reactively responds to customer leak or other service interruption calls for non-program related meter exchanges.

In addition, EGI continues to use data to project MXGI replacement volumes with a focus on leveling volumes over future years. Meters have a complete set of data that includes quantity, age, make, size, location and historical performance. The completeness of this data enhances the optimization of the life cycle strategy.

The replacement program for these assets is mandated by Measurement Canada, which maximizes asset life through sampling and testing, to ensure the required level of metering accuracy. The effectiveness of this program is a result of complete asset data, appropriate data management systems and statistically sound testing methodologies representative of larger population groups. EGI currently forecasts future budgets based on historical results. The projections for 2021-2030 are shown in **Table 5.4-4** and **Table 5.4-5** for the EGD and Union rate zones respectively.

Table 5.4-4: Meter Replacements (Projected) – EGD Rate Zone

Year	MXGI Meter Exchanges	Non-Program Meter Exchanges
2021	48,572	18,980
2022	53,308	19,019
2023	64,266	19,027
2024	59,247	19,113
2025	41,163	19,642
2026	58,071	20,000
2027	55,848	19,967
2028	41,534	20,267
2029	58,203	19,868
2030	58,203	19,868

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Table 5.4-5: Meter Replacements (Projected) – Union Rate Zones

Year	MXGI Meter Exchanges	Non-Program Meter Exchanges
2021	52,299	9,659
2022	52,882	9,783
2023	53,510	9,908
2024	53,400	10,035
2025	54,012	10,163
2026	54,684	10,293
2027	55,337	10,425
2028	55,998	10,558
2029	56,668	10,694
2030	57,347	10,830

MXGI quantities are influenced by historical customer addition patterns and group performance of sampled meters. Previous year sampling results inform a given year's budget. An average of the meter exchanges over the past 10 years were used to project averages for the next 10 years. To further refine longer term forecasting of MXGI quantities, a predictive failure model is being built based on historical extension and failure results of meter groups.

Consistent with the majority of utilities, EGI is considering the deployment of Advanced Metering Infrastructure (AMI). This initiative would modernize and allow two-way communication with the meters by way of a network. It will provide significant benefits to customers–reducing meter reading and call centre costs and eliminating estimated bills while providing customers insight into their gas usage at a granular level so they can make informed decisions. With access to granular usage information, EGI gains needed insights into peak usage. This in turn will support EGI's implementation of IRP plans and may allow the deferral of reinforcement projects.

As EGI continues to review operating standards in each rate zone and the use of various equipment and fittings, plans will be developed to bring these into alignment in a way that balances risk, cost and performance. Examples could include EGI's approach to meter location in high-density townhomes, the standards and maintenance practices for multi-unit buildings, or the installation and maintenance strategies for remote first cut regulators.

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5.4.6 Pressure Regulation and Over-pressure Protection Systems

EGI is accountable for managing 3.2 million regulator sets that deliver low-pressure natural gas to customers. These critical assets act as the last line of defense against over-pressure. A regulator set is comprised of the following components: a regulator that reduces distribution gas pressure to delivery pressure, piping and over-pressure protection devices. Proper performance of these assets is vital for the health and safety of customers, the public and employees. **Table 5.4-6** describes the four subsets of this asset subclass:

Table 5.4-6: Regulator Set Descriptions

Regulator Set	Description
< 17 NCMH (200 and 400 Series Regulator Sets)	These regulator sets provide low pressure delivery (typically 7"wc) to primarily residential customers. Associated with meters having capacities of 17.0 m^3/h or less.
>17 NCMH (>400 Series Regulator Sets)	These regulator sets provide low pressure delivery (typically 7" to 10"wc) to high-volume regulator sets. Associated with meters having capacities greater than 17.0 m^3/h.
Local First Cut Regulator Sets	These regulator sets are associated with services connected to higher-pressure mains and have two regulators in series (both installed adjacent to the building). The first-cut regulator reduces pressure from a higher pressure to an intermediate pressure and the service-cut regulator reduces pressure from intermediate to low pressure.
Remote First Cut Regulator Sets	These regulator sets (also known as farm taps) are associated with services connected to higher-pressure mains (typically in rural areas) and have two regulators in series. The first-cut regulator reduces pressure from a higher pressure to an intermediate pressure and is typically located close to the property line (remote from the premises). The service continues below grade to the service-cut regulator, located adjacent to the premises.

5.4.6.1. 200 and 400 Series Regulator Sets

The 200 and 400 series regulator sets account for the majority (approximately 95%) of all regulator sets. Currently, regulators with single meters are replaced at the same time as meters exchanged through the Government Inspection Meter Exchange (MXGI) program. Based on MXGI program requirements, replacements can happen as soon as after 10 years of service. EGI has begun to collect regulator data as part of the MXGI program–a survey of 6,785 regulator sets in the EGD rate zone confirmed that most regulators have the same age as the meter set. A similar initiative is underway for the Union rate zones.

Using the service installation date as a proxy for the age of the regulator set, **Figure 5.4-7** shows that for the EGD rate zone, 0.002% of 200 and 400 series regulator sets are older than 40 years and 16% are older than 20 years.

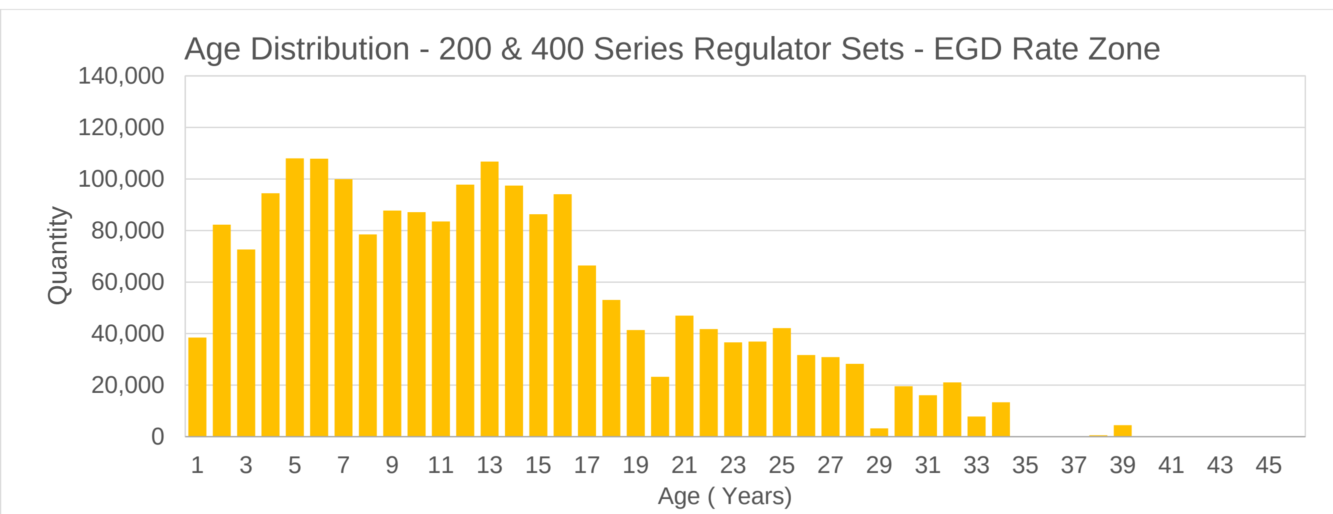

Figure 5.4-7: Age Distribution of 200 and 400 Series Regulator Sets – EGD Rate Zone

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5.4.6.1.1 Condition Methodology

Regulator set condition is determined by performance, corrosion of piping and regulators and adherence to installation specifications:

- **Regulator performance** is influenced by the age of the asset (mechanical wear and tear) and its physical environment, potentially affecting its ability to lock up in abnormal conditions (to prevent over-pressure) and its ability to contain gas (absence of leaks). Assessment is determined through failure data, laboratory testing and age of the asset.
- **Corrosion of piping and regulators** can lead to loss of containment and faulty regulator performance. This is determined through an on-site visual assessment.
- **Adherence to installation specifications** is affected by a number of external factors which can affect failure rates and consequences. These include physical changes in site condition made by the customer after the initial installation of the set, such as new building openings/vents, increased grade and unreported damage, as well as regulatory specifications and codes that have changed since installation. This is determined by an on-site visual assessment.

Issues and outcomes affecting regulator sets, safety devices and piping systems are summarized in **Table 5.4-7**:

Table 5.4-7: Component Issues and Outcomes Summary

Component	Issue	Outcome
Regulator	Incorrect delivery pressure	Undesirable downstream effects can cause an emergency response and potentially higher severity consequences.
External reliefs	External relief missing on downstream regulator	Absence or failure of this component removes over-pressure protection, which is critical in the event of a regulator failure.
Regulator cap	Damaged or missing	A damaged or missing regulator cap can allow water or debris to enter the regulator housing, resulting in faulty performance and compromised pressure control.
Vent	Orientation not downwards	The vent must point downwards to reduce the probability of water or debris entering regulator control components and compromising pressure control.
	Missing or incorrectly sized vent screen	Missing or incorrectly sized regulator vent screens can allow insects and/or debris to block vent openings, impeding regulator diaphragm movement and compromising pressure control.
	Presence of vent shields	Vent shields are legacy components that were in place to protect vents. Debris or ice can build up on the vent shield, causing blockage and compromising pressure control.
	Vent too close to grade	Vents that are too close to grade can experience splashing and freeze-up of the opening, or can be covered with snow/ice, compromising pressure control.
	Insufficient vent clearance to building openings	Vents must comply with minimum distances to building openings to prevent gas migration.
Regulator	Regulator touching customer supply lines	Regulators touching customer supply lines can cause electrical continuity of below- and above-ground systems. This can promote migration of corrosion between below- and above-ground piping.
	Regulator too close to ground	Regulators that touch the ground are more susceptible to corrosion.
Fittings	Buried fittings	Fittings, typically wing-locks, must be above-ground to shut off gas in emergencies and avoid corrosion.
Regulator, Piping, Fitting, External Reliefs	Corrosion	Severe corrosion and pitting can lead to a loss of containment or abnormal operating condition.
All	Damaged by third party or environmental factors	Damages can lead to a loss of containment or abnormal operating condition.

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These issues can contribute to failure of the regulation system and can cause pressured gas to enter the customer's supply piping, resulting in the potential failure of gas equipment, loss of containment, gas accumulation and/or potential incidents.

5.4.6.1.2 Condition Findings

Failure history and trending indicates that the wear-out phase for regulators associated with 200 and 400 series meters is unlikely to occur before 30 years of age. The current failure rate is 0.14% of the total population. EGI replaces regulators before they fail and are exchanged at the same time as the meter–meters are managed through the MXGI program and is based on sampling and testing to ensure Measurement Canada specifications are maintained.

Non-program regulators that fail before the manufacturer's recommended maximum service life are discovered during emergency calls or customer-initiated work. In most years, the number of regulators exchanged outside of the program is very minimal (less than 1% of the population).

Three condition categories evaluated for 200 and 400 series regulator sets are regulator performance, corrosion and adherence to installation specifications:

Regulator Performance: Regulator performance is affected by wear-out due to a combination of internal mechanical cycling and field operating conditions such as the presence of debris in the gas or atmosphere, ice or snow load and regulator set location. Additional layers of protection that are part of EGI's installation standard (e.g., over-pressure protection) can mitigate regulator failure incidents. EGI uses actual regulator failure and exchange data where possible to establish failure modes and frequencies.

For regulators exchanged outside the MXGI program, the historical data does not indicate the reasons for regulator exchanges. A conservative approach for the reliability study assumed that all exchanges were due to some type of failure. Failures may include a relieving regulator, regulator creeping, under-pressure, over-pressure or gas escapes. Non-failure replacements may be due to handling issues, customer load changes, changes to building openings, obsolete regulators, corrosion and damages. In a study completed in the EGD rate zone on regulator exchanges between 2005-2014, it was found that approximately 2800 regulators (0.14% of the population of 2.1 million) were exchanged independent of meter exchanges each year. As part of integration activities, an initiative to obtain similar data for the Union rate zones is underway.

The quantity of regulator exchanges independent of meter exchanges is relatively low. Analysis will be done to distinguish failure and non-failure exchanges within this data set. Going forward, failure classifications in the work and asset management system will improve root cause identification for regulator replacements.

Corrosion: A survey to investigate regulator corrosion on regulator sets was carried out across a population of 20,700 in the EGD rate zone. Corrosion distribution by age is shown in **Figure 5.4-8**.

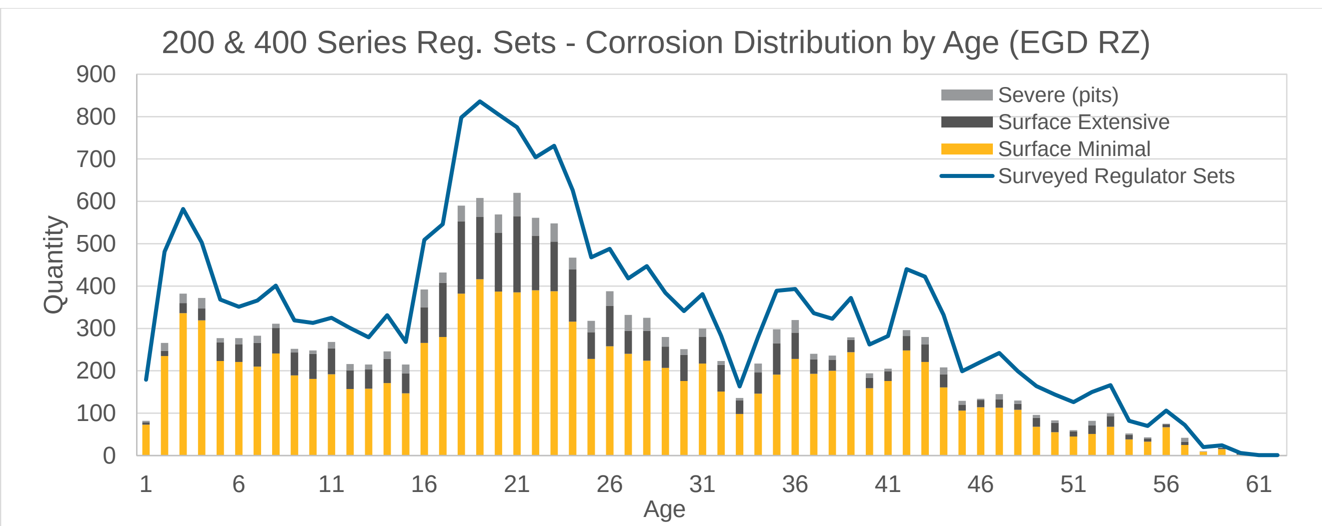

Figure 5.4-8: 200 and 400 Series Regulator Sets - Corrosion Distribution by Age – EGD Rate Zone

Results for the EGD rate zone show that 73% of the surveyed regulator sets have varying degrees of corrosion. Each vintage has at least 50% of the population of regulator sets with signs of corrosion. However, **Figure 5.4-8** shows that the majority of regulator sets have minimal surface corrosion and only 5% was categorized as severe. As part of integration activities, an initiative to obtain similar data for the Union rate zones is underway.

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Adherence to Installation Specifications: It has been observed that regulator sets can have deviations from current installation specifications. This can occur when site conditions change over time, such as buildup of grade level, addition of new vents/building openings and building structures, as well as broken/missing components. In addition, installation specifications have changed over time and legacy specifications and components may still exist in some of these sets. These issues are rectified as part of MXGI program work.

5.4.6.1.3 Risk and Opportunity

200 and 400 series regulator sets in poor condition expose EGI to financial and safety risk. Poor condition can result in the regulator not delivering gas to the premises as designed for the downstream piping and equipment. In turn, this can result in a loss of containment within the building (including gas migration). Delivery pressures outside of normal operating conditions (under- or over-pressure) can also negatively affect appliance performance. If appliance safeguards fail, building occupants may be potentially exposed to carbon monoxide.

The most likely risk is financial risk associated with failure of these assets, which includes emergency response, commodity loss, repair costs and the costs of relighting customers' gas appliances. More severe incidents may also include costs associated with property damage and personal injury due to a gas leak. Regulator failure and customer service disruptions resulting from these failures may also result in reduced customer satisfaction.

The probability of a safety risk is low due to the MXGI program governing these assets. Regulator exchanges through the MXGI program and the policy to remove regulators older than 20 years (as found through service calls) ensure the safety risk is managed.

5.4.6.1.4 Strategy Outcomes

The strategy for 200 and 400 series regulator sets is to continue exchanging regulators and correct other compliance issues as part of the MXGI program, as these critical assets serve the majority of customers in the EGI franchise area.

Run-to-failure is not an acceptable practice for this asset, as the over pressure protection devices associated with the regulators are the last line of defense to protect customers from over-pressure events. The over pressure protection device is usually a part of the regulator set itself. Exchanging the regulators as part of the MXGI program mitigates the population from reaching the wear-out phase and ensures optimum regulator performance and safety.

By exchanging the regulator proactively as part of the MXGI program, the health and safety risk is managed and remains broadly tolerable because compliance issues are resolved before regulator failure. Financial risk is also managed by replacing regulators during MXGI program exchanges. By proactively replacing regulators nearing end-of-life, the financial impact of responding to emergency calls is minimized. A proactive strategy ensures that failures are minimized, reducing customer outages and maintaining high customer confidence in EGI as a gas provider.

This strategy applies a planned and controlled spend of capital dollars, while maintaining the current level of operational reliability. The continuous collection of failure data will help support improvements.

The Regulators and Relief program (specific to the Union rate zones) manages the cost of purchasing and stocking of natural gas regulators and relief valves to support replacement work. As regulators and relief valves fail or require replacement due to age or obsolescence (whether it be at the time of meter exchange or in conjunction with other maintenance projects), regulators are purchased and stocked to help maintain the high reliability of EGI's station assets.

5.4.6.2. >400 Series Regulator Sets

The >400 series regulator sets are primarily used by commercial, industrial and high-density residential customers and account for approximately 4.6% of all regulator sets. Failure of these regulator sets has the potential to cause over-pressure to a customer's supply line and appliances. Over-pressure can result in a loss of containment within the building, potentially allowing gas migration. The current policy states commercial regulators are exchanged if found to be 20 years or older.

Figure 5.4-9 shows that for the EGD rate zone, 20% of the population were installed over 40 years ago and 58% were installed over 20 years ago.

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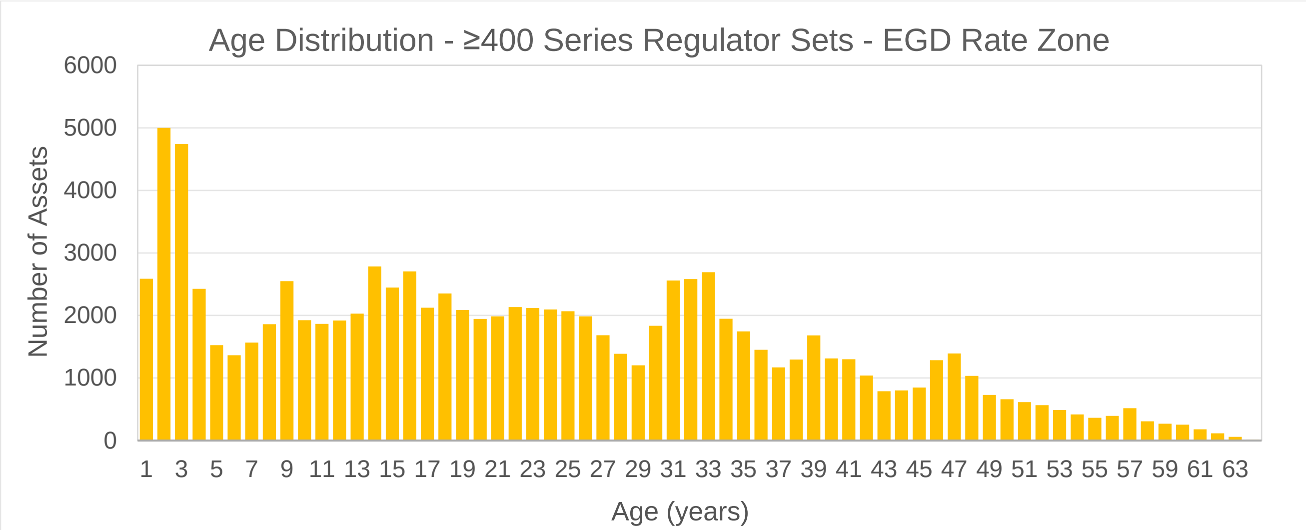

Figure 5.4-9: Age Distribution of >400 Series Regulator Sets – EGD Rate Zone

Commercial Meter Manifolds are a subset of >400 series regulator sets. These installations of multiple banked meters are typically located in commercial plazas. An EGD rate zone survey found this type of >400 series regulator set is more prone to condition issues and non-adherence to installation specifications, as EGI has not historically provided specifications on the addition of new meters to existing manifolds and criteria required for regulator set rebuilds. A risk assessment of this asset class is scheduled, which will assist in the development of an integrated program.

5.4.6.2.1 Condition Methodology

The condition methodology for >400 series regulator sets is the same as for the 200 and 400 series regulator sets. Refer to **Section 5.4.6.1.1**.

5.4.6.2.2 Condition Findings

Three main condition categories were evaluated for >400 series regulator sets: regulator performance, corrosion and adherence to installation specifications.

Regulator performance: **Figure 5.4-9** shows that for the EGD rate zone, more than half of these regulator sets are older than 20 years. Without failure data for these assets, EGI used station regulator failure data as a proxy to determine the probability of failure due to external leaks and ability to lock up. While a regulator used in a station may be the same as a >400 series or local first cut regulator, there are some differences. Using SMA input, a multiplier was developed and applied to the probability of failure to adjust for these differences.

A DIMP program to review the asset health of >400 series regulators not located at a customer station is being proposed to better understand the condition of this population.

External Corrosion: A preliminary visual integrity survey on a small sample population in the EGD rate zone identified issues related to corrosion and adherence to installation specifications. Sixteen percent (16%) of sites had severe corrosion or non-adherence to installation specifications. Thirty-seven percent (37%) of >400 regulator sets had corrosion of some extent. **Figure 5.4-10** shows that light corrosion was most frequently found on these regulator sets across all ages. Heavy corrosion was only found on regulator sets 29 years and older, showing a variation in corrosion across the age population. External corrosion does not affect the engineering design and safe operation of the >400 regulator assets.

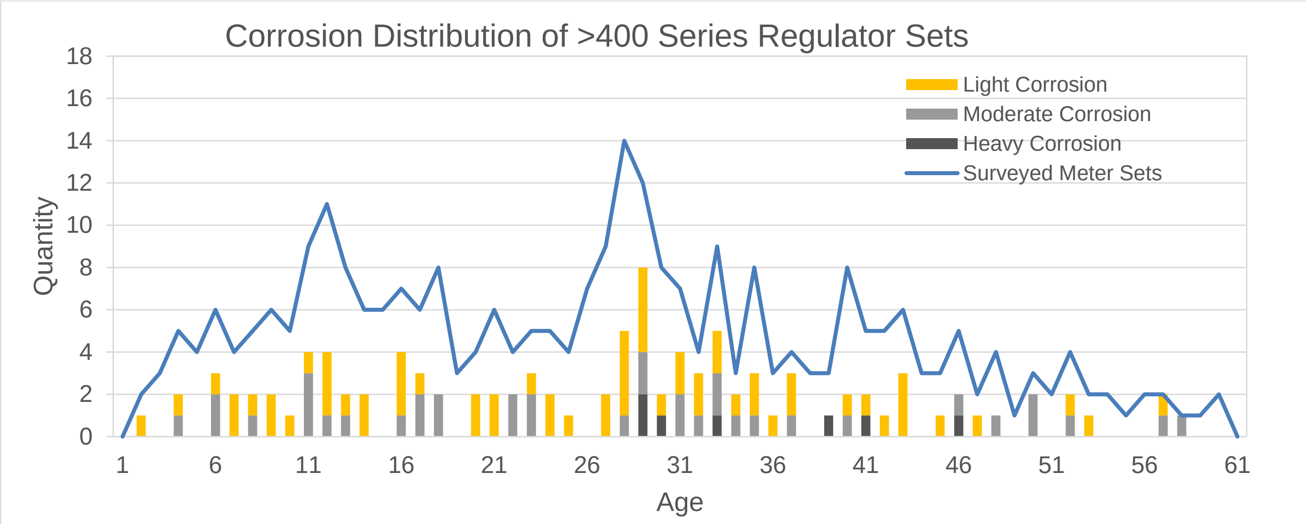

Figure 5.4-10: Corrosion Distribution of >400 Series Sets – EGD Rate Zone

Adherence to Installation Specifications*:* The sample survey also identified sites not adhering to current installation specifications. Results show that non-adherence to installation specifications is not specific to a certain age of >400 series regulator. The most prevalent issues found include:

- Issues with vent clearances and other components
- Regulator touching pipe
- Vent not pointing downward
- Missing vent screen
- Improper valve distance from ground

All installation specification issues are scheduled to be corrected/remediated and the development of a >400 series regulator set sampling program is planned to better understand the condition of this asset population.

As part of integration activities, an initiative to obtain similar data for the Union rate zones is anticipated.

5.4.6.2.3 Risk and Opportunity

Based on historical failure data, the probability of a >400 series regulator failure is low. These assets account for 4.6% of all regulator sets and are predominantly used in commercial, industrial or higher-density residential premises, which typically serve a larger number of end-users than single-family residential premises. An abnormal operating condition for one of these assets puts a larger number of end-users at risk. As well, >400 series regulators have higher delivery flow rates than residential (200 and 400 series regulators) services. This results in potentially more severe consequences for safety and financial risks when compared to smaller flow regulator sets.

EGI may be exposed to a safety risk due to a loss of containment if the regulator cannot control the gas pressure to the premises, leading to an over-pressure event that may damage downstream equipment and property and migrate gas into the customers' premises, resulting in gas accumulation and a potential incident.

Failure of these assets exposes EGI to financial risk. A loss of containment triggers emergency calls which may result in repair costs, commodity loss, relighting customers' gas appliances, property damage and personal injury due to a gas leak. Regulator failure and customer service disruptions resulting from these failures may also negatively impact EGI customer satisfaction.

The most likely risk for >400 series regulator sets is financial, due to the likely outcome of a failure only requiring remediation. The probability of a safety risk is low due to engineering policies governing these assets. Regulator exchanges through the MXGI program and the protocol to remove regulators older than 20 years (as found through service calls) help manage this risk.

5.4.6.2.4 Strategy Outcomes

The strategy for >400 series regulator sets is to replace assets older than 20 years through the MXGI program. Additionally, there are strategies in place through DIMP to collect information on the failure rates of these assets, informing future policy decisions on replacement frequency. The associated services are surveyed for leaks every five years and surveyed for corrosion every year.

>400 series regulator sets typically serve higher-usage and higher-density customers. The safety and reliability impacts of an incident could be high. A risk assessment will be completed for these assets to determine mitigation strategies. By proactively inspecting and remediating issues on a priority basis, the risk of an in-service failure will be reduced. If these regulator sets are allowed to run to failure, there will be inconvenience to the customer, a financial impact due to emergency call responses and the possibility of a health and safety incident.

This strategy manages safety risk by remediating all discovered compliance and integrity issues before they turn into failures, minimizing the risk to the safety of customers, employees and the public. Remediation may entail a full replacement of the regulator, meter and riser, as well as adjustments to bring the regulator set to current installation specifications. The planned and controlled spend of capital dollars minimizes the financial impact of responding to emergency calls. The strategy supports operational reliability by ensuring that failures continue to be very minimal, minimizing customer outages and maintaining high customer confidence in EGI as a gas provider.

In 2017, a sample survey was completed for this asset class in the EGD rate zone. Similar to the assets in Measurement Systems, the continuous improvement strategy for this program is made possible through data collection. Data will be used to optimize the renewal schedule and potentially change the program pace. Data will continue to be collected on regulator sets that become part of the MXGI program. Data such as condition, adherence to installation specifications, regulator attributes and failure classifications will be collected to iterate data models. Refinements include validating criteria that assist in prioritizing high risk locations and analyze asset life cycle and risk assessments.

As part of the integration activities, programs to assess the >400 series regulator sets are being developed to better understand the condition of the broader population in both rate zones and to determine if further proactive processes or programs are required to ensure safe and efficient operations.

5.4.6.3. Local First Cut Regulator Sets

When gas is delivered from a higher-pressure (>100 psig) gas main, the regulator set will have two regulators installed in series (i.e. two pressure cuts). This configuration is not common and represents an estimated less than 2% of the total 3.2 million EGI services. In the local first cut regulator set configuration, the first regulator reduces gas pressure from higher-pressure gas main to intermediate pressure (typically in the range of 60 psig) and the second regulator reduces pressure from intermediate pressure to the delivery pressure (up to 14” WC). The regulator set may also include additional components, such as external relief valves.

The entire local first cut regulator set population for the EGD rate zone was surveyed in 2015 and 2016 to identify and remediate any immediate concerns (e.g. missing first cuts, leaks, improper relief vents, etc.) and to assess the asset population’s fitness for service. The age distribution of these regulator sets is shown in **Figure 5.4-11**. Programs to assess this asset subclass are being developed to better understand the condition of the broader population for both rate zones.

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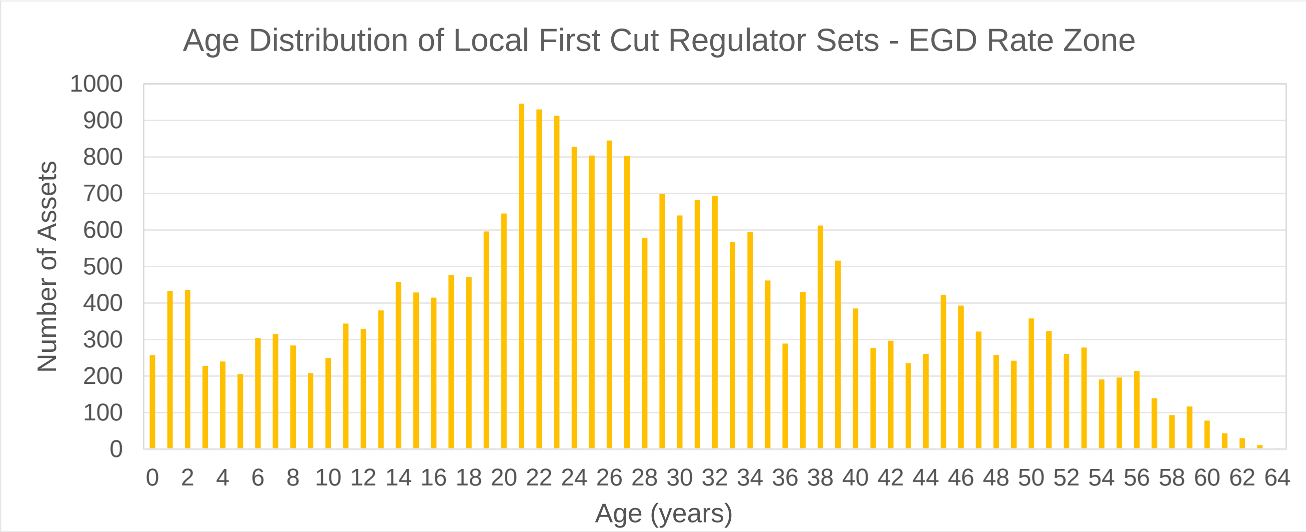

Figure 5.4-11: Age Distribution of Local First Cut Regulator Sets - EGD Rate Zone

5.4.6.3.1 Condition Methodology

The condition methodology for local first cut regulator sets is the same as for the 200 and 400 series regulator sets. See **Section 5.4.6.1.1**.

5.4.6.3.2 Condition Findings

Three main condition categories were evaluated for local first cut regulator sets in the EGD rate zone: regulator performance, corrosion and adherence to installation specifications.

Regulator Performance: Failure data specific to local first cut regulators has not historically been categorized. Station regulator data was used as a proxy in determining the probability of failure due to external leaks and the ability to lock up.

Corrosion of piping and regulators: A survey of local first cut regulators in the EGD rate zone was conducted to identify corrosion and issues with adherence to installation specifications. Seventy-eight percent (78%) of the total population was found to have some minimal degree of corrosion. **Figure 5.4-12** shows that most sites with signs of corrosion have minimal surface corrosion. All sites with severe corrosion have been remediated.

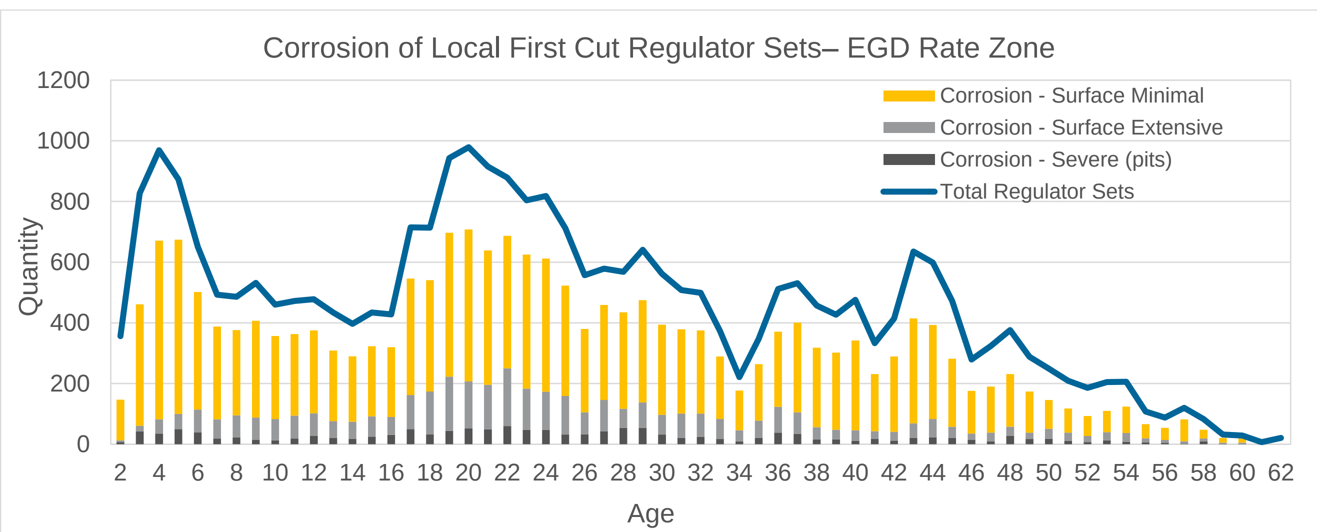

Figure 5.4-12: Corrosion of Local First Cut Regulator Sets– EGD Rate Zone

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Adherence to Installation Specifications: Non-adherence to installation specifications were found on some of first cut regulator sets. Some of the issues identified include:

- Improper vent orientation
- Damage to the regulator cap
- Missing vent screens
- Presence of vent shields
- Missing external reliefs

All of the EGD rate zone sites with these issues were prioritized based on the likelihood of an incident occurring and were all remediated. Generally, older regulator sets were more likely to exhibit these issues as there is more likelihood of changes to site conditions and changes to installation policies. Sites found to have old/obsolete regulators were also remediated. The asset survey also found sites with minor specification issues–a program to remediate the rest of these minor variances is ongoing.

A process to identify and survey first cut regulator sets in the Union rate zones will start in 2020.

5.4.6.3.3 Risk and Opportunity

All distribution system pressure regulation systems have an inherent level of risk. Risks associated with local first cut regulator sets are safety and financial risks, due to the likely outcome of a failure only requiring remediation. The safety risk is low due to EGI policies for these assets (i.e. regulator exchanges through the MXGI program and removal of regulators older than 20 years).

The safety risk associated with local first cut regulator sets is associated with the loss of gas containment. Regulators (and associated relief valves) control gas pressure to protect the customer's piping and premise from over-pressure. An over-pressure event can result in damage to downstream equipment, loss of containment within the building, gas accumulation and a potential incident. A local first cut regulator set presents a higher consequence than traditional single cut regulator sets due to the higher pressures managed by two pressure cuts. The failure rate of local first cut regulator sets is very low due to the presence of multiple pressure regulators and multiple over-pressure protection devices installed in series.

The financial risk associated with first cut regulator sets is a consequence of responding to the events associated with the safety risk. Over-pressure and loss of containment generates costs associated with emergency response calls, repairs, commodity loss, relighting customers' gas appliances, property damage and/or other claims. Customer service disruptions and media coverage resulting from these events may result in reduced customer confidence in EGI.

5.4.6.3.4 Strategy Outcomes

The strategy for local first cut regulator sets is to proactively maintain and exchange units in conjunction with the MXGI program. Reactive maintenance is on an as-needed basis to address customer leaks and/or emergency calls.

In order to ensure safety and reliability, EGI employed a variety of strategies to replace regulators prior to failure while extending their useful life. Assets identified with 200 and 400 series meters have regulators proactively replaced in conjunction with the MXGI program:

- First cut regulator and external relief valves are replaced when the second cut regulator is replaced.
- Regulators on commercial local first cut regulator sets are replaced if found to be 20 years or older, maintaining asset integrity, extending asset life and ensuring code compliance.
- Local first cut regulator sets are included in a data survey every four years and a comprehensive survey every eight years.

The continuous improvement strategy for this program is made possible through data collection. Data will continue to be collected on regulator sets that become part of the MXGI program. Data such as condition, adherence to installation specifications, regulator attributes and failure classifications will be collected to iterate data models. Refinements include validating criteria that assist in prioritizing high-risk locations and analyze asset life cycle and risk assessments.

As part of integration initiatives for the Utilization asset class, programs to assess local first cut regulator sets are being developed to better understand the condition of the broader population in both rate zones and to determine if further proactive processes or programs are required.

For the EGD rate zone, all immediate safety concerns from the 2015-2016 survey were remediated. As well, a strategy is in place to remediate remaining sites found to have minor compliance issues. Remediation measures are site-dependent. Remediation may entail a full replacement of the regulator set or may only require adjustments to bring the regulator set to current installation specifications.

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Financial risk is managed through a planned and controlled spend of capital dollars. By proactively managing the health of local first cut regulator sets, the financial impact of responding to emergency calls is minimized. Customer satisfaction is managed by ensuring failures and corresponding customer outages are minimized. This strategy supports operational reliability, efficiency and safety.

For the Union rate zones, integration initiatives will allow for better documentation and asset health assessment of local first cut regulator assets.

5.4.6.4. Remote First Cut Regulator Sets (Farm Taps)

These double cut regulator sets (referred to as farm tap regulator configurations) make up less than 0.5% of all regulator sets. The majority of these assets are found in rural areas. A farm tap is a first cut regulator that reduces pressure from a higher to intermediate pressure to meet the design criteria for the downstream regulator. A malfunctioning farm tap regulator has the potential to create downstream hazards. A failure of the regulator set could potentially cause a higher than acceptable pressure entering customer premises. This over-pressure can result in downstream customer appliances failing, loss of containment inside the premises, gas accumulation and a potential incident.

As most farm tap regulators are installed away from the premises and near the property line, these assets are exposed to more elements originating from the roadway. Their placement can also make them susceptible to third-party damage from maintenance equipment and vehicles.

The majority of farm taps are 20 years old or younger (see **Figure 5.4-13**). In 2017, an inspection and remediation program in the EGD rate zone targeted the farm tap population 20 years and older. This program is currently ongoing.

For the Union rate zones, a sample survey of farm tap regulators is currently proposed for 2020 to provide initial knowledge on the condition of the asset subclass.

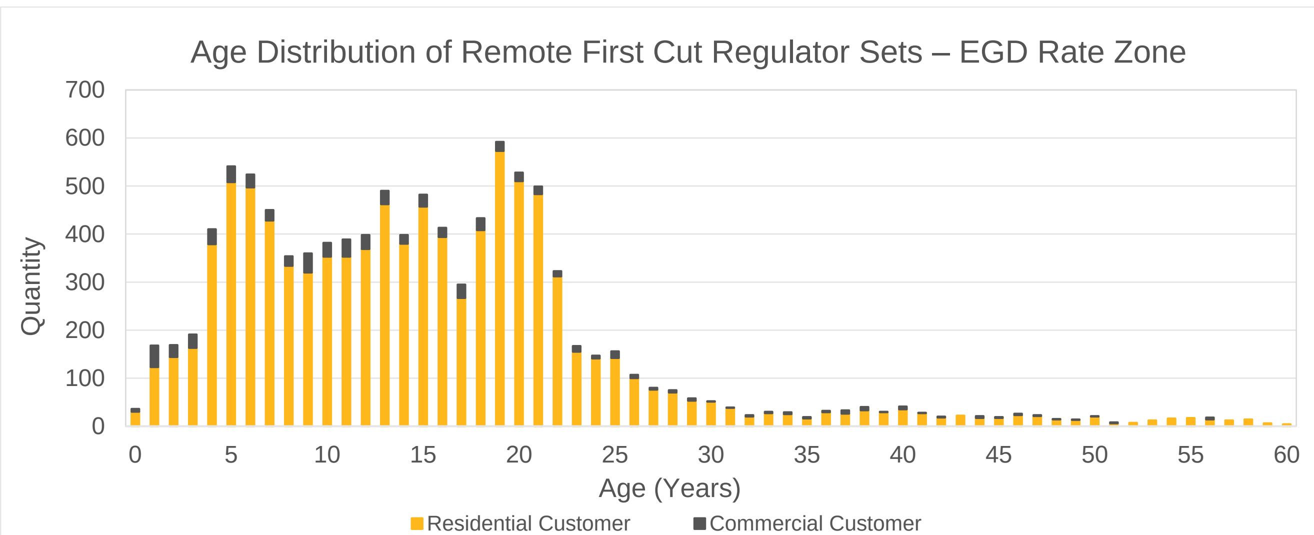

Figure 5.4-13: Age Distribution of Remote First Cut Regulator Sets – EGD Rate Zone

5.4.6.4.1 Condition Methodology

The condition methodology for remote first cut regulator sets is the same as for the 200 and 400 series regulator sets. Refer to **Section 5.4.6.1.1**.

For the EGD rate zone, a component-based Failure Mode and Effect Analysis (FMEA) was performed through SMA reviews to identify the critical components of all remote first cut regulator sets, their failure modes, causes and effects, required safeguards and potential consequences if safeguards fail.

5.4.6.4.2 Condition Findings

Sites for remote first cut regulator sets older than 15 years were determined to have more significant condition issues. Three main condition categories were evaluated for these assets: regulator performance, corrosion and adherence to installation specifications.

Regulator performance: Service regulators are required to be replaced if found to be 20 years or older. The current exchange policy also includes exchanging the regulator if the second cut regulator is being exchanged as part of the MXGI program. For the EGD rate zone, a program is currently in place to inspect and remediate remote first cut regulator sets older than 20 years to reduce the likelihood of age-related failures.

Failure data specific to remote first cut regulator sets has not historically been categorized. However, a visual integrity survey was conducted in 2015 on a sample population in the EGD rate zone. The issues identified in this survey formed the basis for future remediation work. Reliability modelling analysis was performed on remote first cut regulator sets through the Asset Health Review program using station regulator data as a proxy to help determine the condition of the assets. Over time, more remote first cut regulator set data will be collected and used for reliability modelling.

Corrosion of piping and regulators: Data from the 2015 sample survey in the EGD rate zone provides insight into the asset condition of farm taps. The extent of corrosion versus age is displayed in **Figure 5.4-14**.

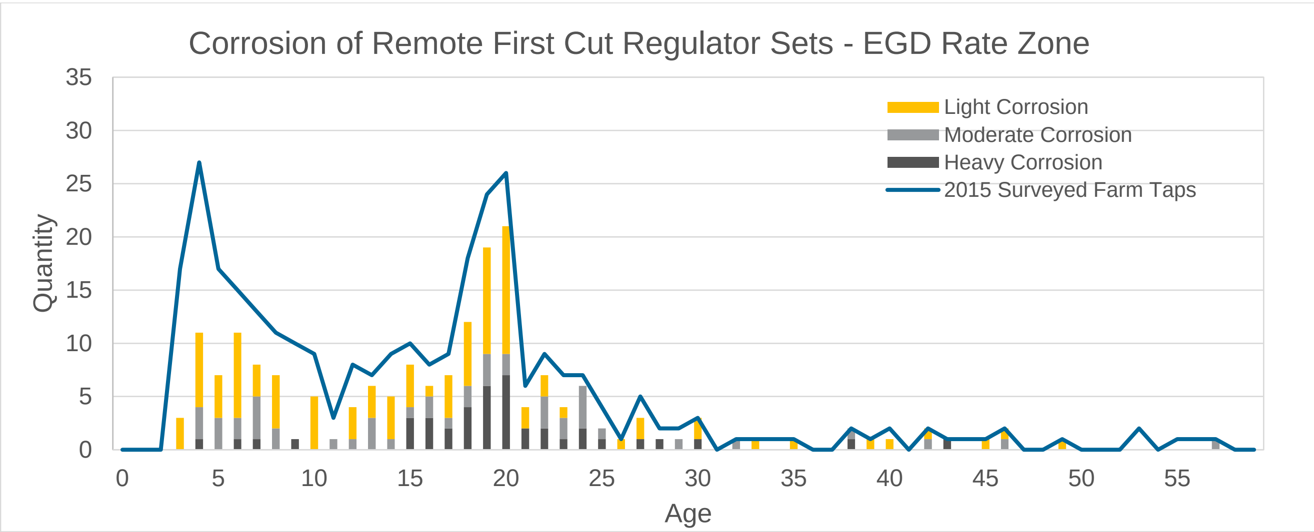

Figure 5.4-14: Corrosion of Remote First Cut Regulator Sets - EGD Rate Zone

Figure 5.4-14 indicates that a higher count of corrosion impact is observed on remote first cut regulator sets 15 years and older. This is attributed to their typical location (in rural areas above-ground and near roadways).

Adherence to installation specifications: The sample survey indicated that some remote first cut regulator set installations had issues related to adherence to installation specifications. The most frequent issues are as follows:

- Vent clearance issues
- Improper vent orientation
- Broken caps
- Missing vent screens
- Obsolete regulators

Most vintages had some level of non-adherence to installation specifications with an increasing trend as these assets approached 20 years of age. This is due to site conditions and installation specifications changing over time.

Based on the survey, remote first cut regulator sets older than 20 years were determined to have more significant condition issues and were prioritized for remediation. A proactive strategy to inspect and remediate these assets will prevent a potential peak in future failures. This approach also distributes future workload while reducing risk.

Based on the FMEA, the main critical components for farm taps are regulators, inlet and outlet shut-off valves, inlet and outlet risers, external relief valves and piping and fittings. A review of the potential consequences of these component failures reveals potential health and safety risks. The FMEA identifies the lack of maintenance as one of the main causes of failures on these critical components.

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For the Union rate zones, a sample survey of farm tap regulators is currently proposed for 2020 to provide initial knowledge on the condition of the asset subclass.

5.4.6.4.3 Risk and Opportunity

Remote first cut regulator sets present higher risks due to the higher pressures managed by the regulator. Downstream of the remote first cut regulator is a second regulator cutting pressure to the service premises. The probability of failure of the service cut regulator is evaluated to be the same for all service regulators of any flow capacity delivering low pressure.

EGI may be exposed to a safety risk due a loss of containment if the regulator cannot control the gas pressure to the premises, leading to a gas over-pressure event that may damage downstream equipment and property and migrate into the customer's premises, resulting in gas accumulation and a potential incident.

Failure of these assets exposes EGI to financial risk. A loss of containment triggers emergency calls which may result in repair costs, commodity loss, relighting customers' gas appliances and property damage due to a gas leak. Regulator failure and customer service disruptions resulting from these failures may result in poor customer satisfaction .

The most likely risk for these assets is financial, followed by safety risk, due to the likely outcome of a failure requiring remediation. The probability of a safety risk is low due to internal engineering policies governing these assets. Regulator exchanges through the MXGI program and the protocol to remove regulators older than 20 years (as found through service calls) help manage this risk.

5.4.6.4.4 Strategy Outcomes

For the EGD rate zone, remote first cut regulator sets have largely been excluded as part of inspection and maintenance work due to their offset location and changes in procedures over time. A risk assessment will be completed in 2020 to determine mitigation strategies. Remediation may entail a full replacement of the regulator, meter and riser, as well as adjustments to bring the regulator set to current installation specifications.

The FMEA results on remote first cut regulator sets showed that a routine inspection and maintenance program over the lifetime of the asset would reduce in-service failures through the proactive identification of assets that have failed or are nearing end-of-life. After the full risk assessment for both rate zones is complete, a program will be developed to manage this asset subclass. Additionally, remote first cut regulator sets associated to 200 and 400 series meters are exchanged through the MXGI program. Current EGI policy requires the first cut regulator and external relief valves to also be replaced when the second cut regulator is replaced. As part of the Leak Survey program, remote first cut regulator sets are included in the four-year data survey cycle and the eight-year comprehensive survey cycle.

The strategy for these assets is to manage the safety risk by identifying and remediating potential compliance and integrity issues before they turn into failures, minimizing the risk to the safety of customers, employees and the public. This strategy will also minimize the financial impact of responding to emergency calls.

This proactive strategy ensures that the risk of failure is mitigated, minimizing customer outages and maintaining high customer confidence in EGI as a gas provider.

For the Union rate zones, a sample survey of remote first cut regulator sets is planned for 2020 and will provide initial knowledge on the asset subclass condition. As part of integration activities, a remote first cut regulator set assessment program will be developed to better understand the condition of the broader population at both rate zones and to determine if further proactive processes or programs will be required to ensure safe and efficient operations.

5.4.7 Below-ground and Internal Piping Systems

Below-ground and inside piping systems refer to piping running below grade and/or piping running inside a building, typically located upstream of inside meters. The Below-ground and Internal Piping Systems subclass is categorized into:

Service Extensions: Refers to service piping installed between the regulator (outside of the building) and the meter (inside the building) where the pipe enters the building below ground.

Multi-Family Building Services: Refers to gas distribution networks within multi-unit buildings. Each may consist of a garage header, vertical headers, off-garage service pipes and/or vertical headers supplying meters for individual units. There are two main metering configurations:

- **Ensuite Metering**: internal piping leading to meters inside individual units
- **Banked Metering**: internal piping leading to meters grouped together in the garage or basement on each individual level of the building

Bulk Meter Headers: Refers to gas distribution networks consisting of underground piping downstream of a meter feeding multiple individual customer buildings. Regulation occurs downstream of the meter. These networks are installed by EGI.

5.4.7.1. Service Extensions

Service extensions refer to EGI-owned steel piping from the regulator (outside the building) to the meter (inside the building). Its entry through the building wall is below grade. Service extensions are commonly found at urban wall-to-wall premises. Due to lack of frontage space at these locations, the riser, regulator and service extension are outside the building and the meter is located inside the basement. EGI currently has 13,666 service extensions that are found on 0.7% of services in the EGD rate zone. A study will be conducted in 2022 to determine the number of service extensions for the Union rate zones.

Figure 5.4-15 shows the age distribution for service extensions. The majority of the population is younger than 25 years. Some factors contributing to installations within this timeframe include the renewal of cast iron systems in downtown Toronto and a program moving regulators from inside to outside customer premises.

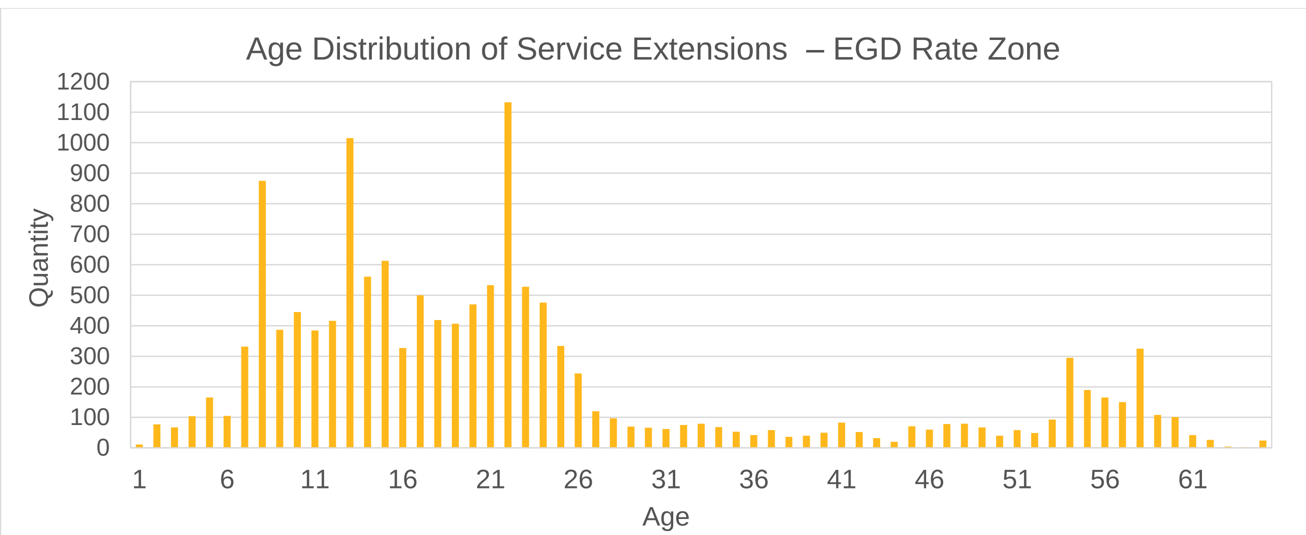

Figure 5.4-15: Age Distribution of Service Extensions – EGD Rate Zone

5.4.7.1.1 Condition Methodology

All service extensions are isolated from cathodically protected steel services. Service extensions with depleted anodes are unprotected and more susceptible to corrosion, ultimately resulting in a loss of containment. Cathodic protection and coating types are two parameters influencing corrosion rate. The application of cathodic protection on service extensions in the EGD rate zone was estimated by conducting pipe-to-soil inspections on a statistically representative sample. In addition, samples of unprotected service extensions were removed to determine wall loss. The sample sites were also inspected prior to

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removal with non-destructive guided wave testing, designed to detect the magnitude and location of wall loss on buried pipe. Removed samples were inspected for condition and to validate the effectiveness of this technology. Installations were upgraded at all sample sites. Through integration efforts, the size and condition of the service extension population in each rate zone will be established.

5.4.7.1.2 Condition Findings

In the EGD rate zone, a cathodic protection survey determined some correlation between age and cathodic protection status (see **Figure 5.4-16**). Newer installations were more likely to be cathodically protected. Older service extensions were more likely to fail than newer service extensions. Twenty-four service extension sites identified as older than 50 years old were removed and replaced to assess pipe condition.

The results of the sample survey were used to refine a mechanical model that will determine the degradation rate of unprotected service extensions. The sampling validated the functionality of non-destructive guided wave technology for use in future inspections.

Further data collection is in progress to improve EGI's understanding of the service extension population and its condition. When complete, sites will be inspected for cathodic protection and if required, a program will be established to replace or improve the cathodic protection of these assets.

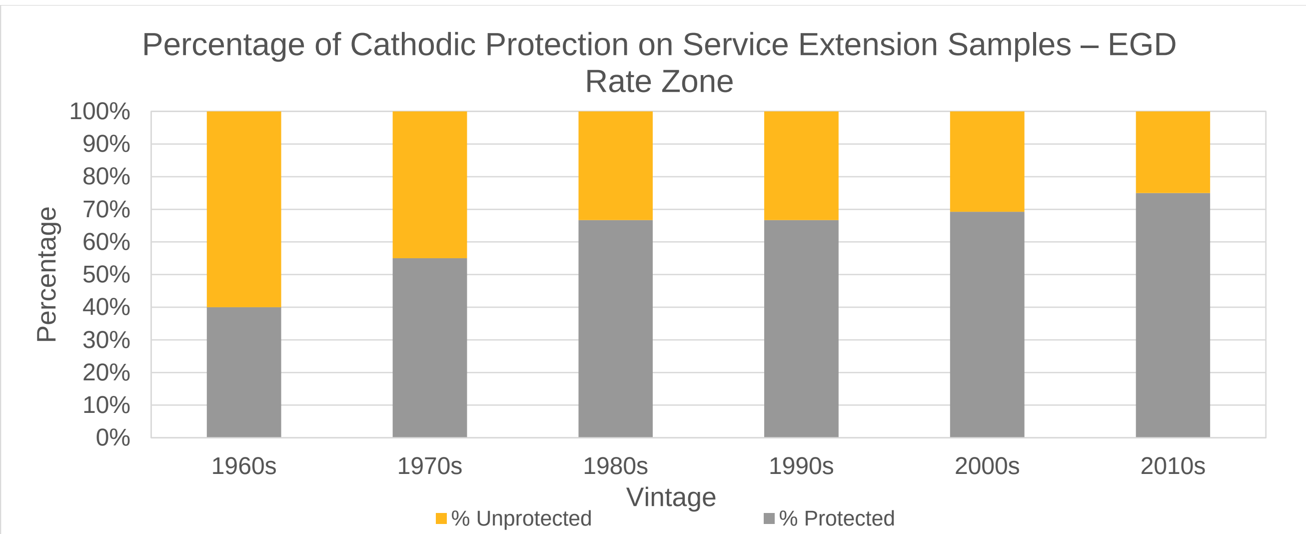

Figure 5.4-16: Percentage of Cathodic Protection on Service Extension Samples – EGD Rate Zone

5.4.7.1.3 Risk and Opportunity

If service extensions are not cathodically protected and properly coated, they can corrode at a higher rate than expected, eventually leading to a loss of containment if not remediated. Since this piping enters the building below grade, gas leaks may have a higher chance of migration into the building, resulting in gas accumulation and a potential incident. The EGD rate zone sample survey shows that the proportion of service extensions without cathodic protection increases with age. This may be due to old installation practices and depleted anodes over time.

Historical frequencies of failures for service extensions are low relative to the total population. Failure consequences can be high they include the potential for underground gas migrating into a building. As natural gas is odourized, leaks are likely to be detected and remediated before a hazardous indoor gas concentration is reached.

The safety risks identified for service extensions are gas leaks and gas migration. Identified financial risks include unplanned repair and relight costs, commodity loss and property damage caused by gas leaks. Service disruptions resulting from these failures may result in poor customer satisfaction.

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5.4.7.1.4 Strategy Outcomes

The strategy for this asset subclass is to opportunistically replace service extension assets in conjunction with planned and unplanned service replacements and planned city sidewalk/road replacements. Comprehensive surveys were conducted in the EGD rate zone to verify the location of these assets. In addition, leak surveys include inspections for leaks up to the meter.

In parallel, these assets will be added to the Corrosion Monitoring program. Condition data will be collected over time, refining the failure model to more accurately predict end-of-life of these assets. In addition, current EGI policy requires adequate cathodic protection to be installed at the time of service extension installation.

Should the risk profile increase over time, a proactive approach of inspection and remediation will be considered. The collection of installation, condition, failure and maintenance data on the majority of the service extension population can be used to validate high-risk location criteria, reduce risk prioritized and supported by data and refine the remediation and inspection program pace.

This strategy will minimize safety risk by remediating integrity issues before they turn into failures and will also minimize the financial impact of responding to related emergency calls. This opportunistic approach minimizes costs associated with proactively renewing these assets.

5.4.7.2. Multi-Family Building Services

Multi-family building installations differ from typical installations significantly by having company-owned pipe within a building. The buildings are typically multiple-storied and contain many independent premises, each with their own meter installed either ensuite or in a rack of meters within the building. These buildings can also be multi-family occupied town housing or row housing.

This piping can contain pressure regulated by a customer station or a low pressure delivery regulation set. With ensuite configurations, the network of EGI-owned piping is extensive, as it includes all of the piping leading to each meter on different floors of the building. With banked metering configurations, company-owned piping typically terminates in a common area (such as a garage) where individual customer meters are grouped together.

5.4.7.2.1 Condition Methodology

Multi-family building installations have several challenges:

- Installation standards allow for these buildings to have higher pressure gas than a single-family residential unit.
- Piping location creates challenges for leak and cathodic protection surveys.
- Some units may have isolated steel pipe upstream of the meter.
- Unit density means potential incidents can have a greater impact.

In the EGD rate zone, leak surveys for multi-family building services are conducted once every three years. A system extract based on residential customers and two or more inside meters indicates there may be other locations that will need to be inspected. The extract aims to identify additional in-scope sites (such as row-housing with internal headers).

Figure 5.4-17 shows the distribution of vintages for this asset subclass, as well as the distribution of inside meters per building at these potential locations.

The scope expansion of the design standard for these assets also affects the scope and locations included in the Leak Survey program. A building with internal distribution piping that has not been included in the program has a high probability of not being inspected for leaks and condition issues since installation. If this internal piping is in poor condition, not physically supported properly, or damaged, there could be a loss of containment and gas accumulation within the building, making an incident possible.

An inventory investigation will determine how many of these configurations are in the Union rate zones. Once known, a survey of each site will be conducted and the assets will be included in Leak Survey and Cathodic Protection programs.

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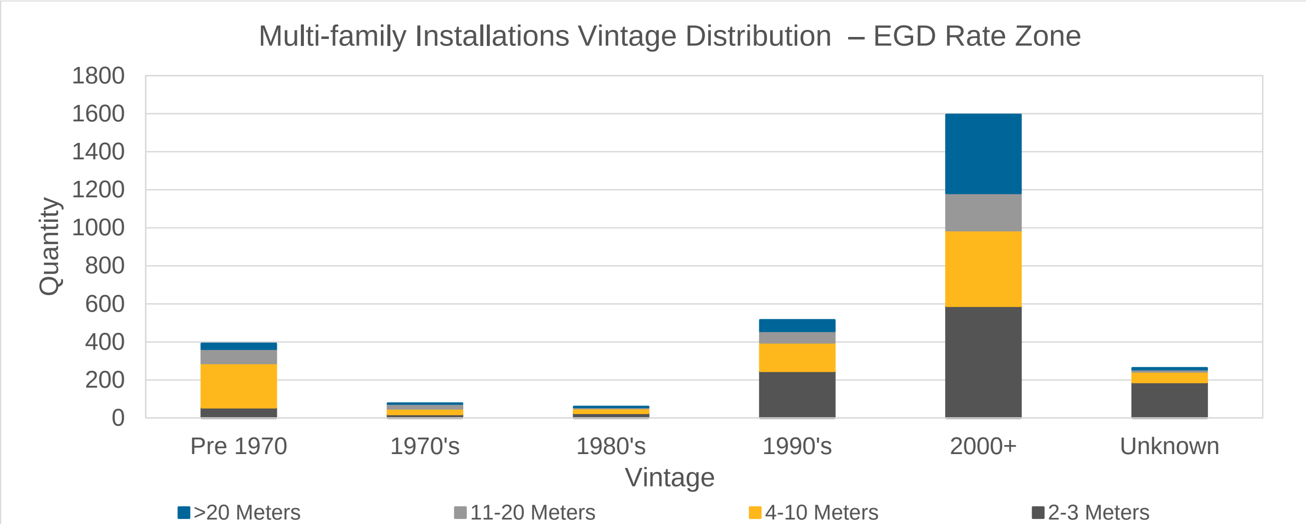

Figure 5.4-17: Multi-family Installations Vintage Distribution – EGD Rate Zone

In the EGD rate zone, two main condition categories were evaluated for multi-family building services:

Adherence to Installation Specifications

- Proper support for piping by approved bracketing and minimum spacing
- Proper support and spacing of meters
- Meter location: fit for purpose, vulnerability to damage, ventilation grille if enclosed
- Identification markings per code
- Pipe penetration through walls and floors and the provision of insulating fittings
- Valve location and accessibility
- Physical barriers: existence, location and condition

Corrosion

- Presence of corrosion on piping
- Presence of corrosion on joints
- Pipe penetration through walls, floors and into the building
- Presence of corrosion on valves
- Adequate corrosion protection

An inventory investigation is being completed under the Distribution Integrity Management Program (DIMP) to review all indoor meters excluded from the Leak Survey program and determine which belong to the multi-family building services population.

5.4.7.2.2 Condition Findings

EGI's leak survey program provides insight into the condition of multi-family building services assets. Generally, corrosion is found where the pipe intersects with the concrete wall–any severe corrosion that could affect safety is remediated. Any leaks found on these assets are remediated immediately. Given the nature of these systems, leaks that do occur are very minor. Any safety concerns are reviewed with the resident or landlord–instances such as encroaching on EGI assets have been found. The inventory investigation will give further insight to the population and will be monitored as part of an engineering integrity program.

5.4.7.2.3 Risk and Opportunity

If internal piping is in poor condition, not physically supported properly or damaged, there could be a loss of containment and gas accumulation within the building, making an incident possible. Buried piping from outdoor regulators to indoor meters is also at risk of leaking and migrating gas indoors. Since this piping system category is located inside high occupancy buildings, the potential consequence of failure is higher. Loss of containment will impact more people, resulting in a greater probability of personal injury. The historical frequency of incidents related to multi-family building services is low.

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To ensure the safety risk remains low, programs are in place to identify these assets and to include them in programs that monitor condition, prevent failure and minimize failure impacts.

The safety risks for multi-family building services assets are gas leaks and migration through underground infrastructure into buildings, resulting in gas accumulation and potential incidents. The financial risks identified are losses due to repair costs, commodity loss, relighting customer gas appliances and any property damages caused by a gas leak. Operational risks identified are greenhouse gas emissions, environmental impacts and service interruptions. EGI continues to take steps to gather necessary information and better manage these assets and their risks.

5.4.7.2.4 Strategy Outcomes

The strategy for multi-family building services assets has two key components:

- Continue to conduct Leak Survey and Cathodic Protection Survey programs based on operating standards for existing multi-family building services assets.
- Continue to conduct population surveys to refine the total asset population and to understand asset condition.

Inventory surveys help ensure adequate corrosion protection and adherence to installation specifications. Data will be used to quantify risk and to determine if existing programs can mitigate these risks. If the risks cannot be managed within the scope and timing of existing programs, a targeted remediation program will be created to address issues identified.

This strategy manages safety risk by remediating all discovered compliance and integrity issues before they turn into failures, minimizing the risk to the safety of customers, employees and the public. This proactive strategy ensures that failures are prevented, minimizing customer outages and maintaining high customer confidence in EGI as a gas provider. As well, this strategy will help improve current levels of operational reliability.

5.4.7.3. Bulk Meter Headers

Some premises that have multiple buildings or suites are served natural gas through a common meter set, where the meter measures the consumption of all buildings or suites collectively (known as a bulk meter). Gas pressure may be reduced at either the same location as the bulk meter, or it may be regulated elsewhere downstream in the system, possibly even at each suite or building. Examples include:

- Multi-family buildings/townhouses
- Farms equipped with multiple fans for crop drying
- Academic, assembly, industrial and military campuses
- Shopping malls or plazas

An example of this type of configuration is shown in **Figure 5.4-18**. Note that the piping downstream of the bulk meter operates at intermediate pressure, the same pressure as the gas main serving the bulk meter.

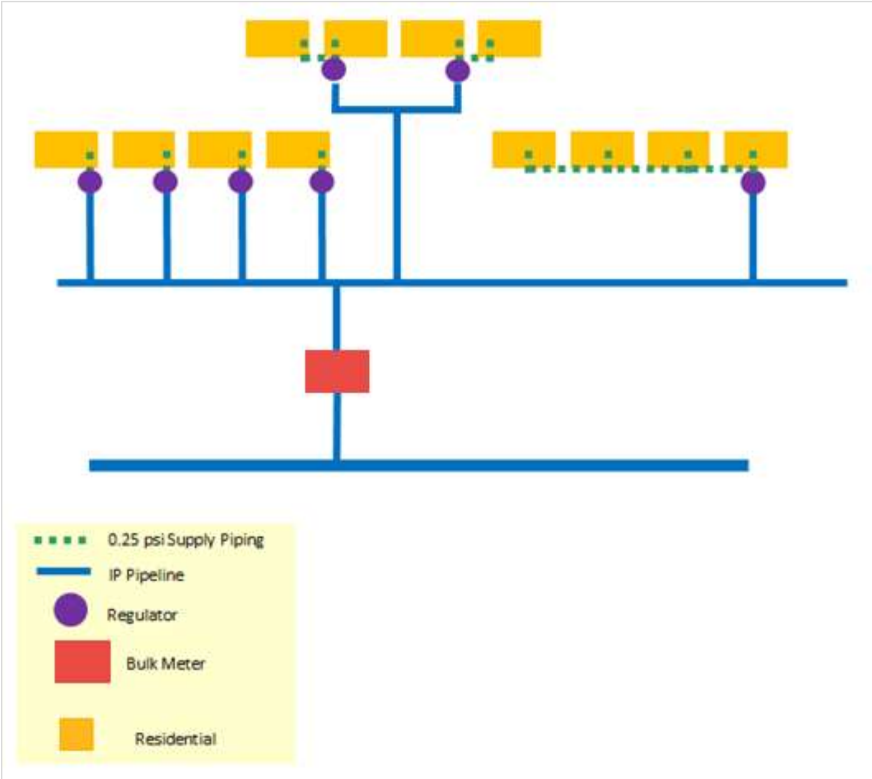

Figure 5.4-18: Bulk Meter Header Sample Configuration

5.4.7.3.1 Condition Methodology

In the EGD rate zone, 18 multi-residential locations with bulk meters were inspected to determine the existence of the following condition factors:

- Obsolete regulators 20 years and older
- Type of regulation
- Riser corrosion
- Lack of maintenance and plant oversight for more than 15 years as per records
- Evidence of unreported third-party damage
- Above ground copper loops
- Compression fittings
- AMP-fittings
- Header and service location unknown due to damaged tracer wire
- Materials and pressures not in compliance with *CSA B149.1* (downstream of the meter)
- Adherence to current installation specifications (vent clearances and configurations, all fittings above-ground, no obsolete components)

These findings, along with site factors such as the number of units and location, were used to remediate all sites in the initial survey.

In the Union rate zones, a process to identify bulk meter sites is being developed and a subsequent survey of the sites will be conducted.

5.4.7.3.2 Condition Findings

For EGI, the most common condition issues found on bulk meter headers are:

- No clear demarcation point between company and customer assets
- Obsolete regulators 20 years and older
- Non-adherence to current installation and maintenance specifications (records, leak and corrosion surveys)
- Vent clearances and configurations not met, not all fittings above-ground and obsolete components

5.4.7.3.3 Risk and Opportunity

Historically, the probability of failure is low for these assets. However, bulk meter headers have a high significance if failure was to occur since the buildings serviced are higher-occupancy units. Safety risks are related to gas leaks and migration through underground infrastructure into buildings, resulting in gas accumulation and potential incidents, as well as the additional risk of unclear demarcation between EGI and customer assets to identify who is responsible for maintenance and repairs. Financial risks identified are losses due to repair costs, commodity loss, relighting customer gas appliances, property damages and personal injury caused by a gas leak. Customer satisfaction may also be negatively impacted by service interruptions.

An initiative for bulk meter headers was created to ensure safe and reliable service to customers. Compliance with existing EGI policies on these assets will keep the safety risk low. The current process for assessing and remediating bulk meter sites provides continuous improvements and ensures the risk remains low.

5.4.7.3.4 Strategy Outcomes

In the EGD rate zone, bulk meter header configurations create uncertainty about the responsibility for asset maintenance. As a result, many of these sites may not have been maintained since installation. The strategy for this asset subclass is to clarify the delineation point between EGI- and customer-owned assets.

All bulk meter sites at multi-residential premises in the EGD rate zone were surveyed and changes in delineation and any necessary retrofits of the piping system were remediated. These improvements help to ensure EGI-owned assets are included in the relevant integrity management programs and allows EGI to communicate with the customer on the required maintenance of the systems they own.

The strategy for the Union rate zones will be determined following an inventory assessment of assets in this subclass.

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5.4.8 Customer-owned Systems

Customer-owned systems are assets that are owned and maintained by the customer and located downstream of EGI-owned assets. Despite not owning these assets, EGI strives to obtain condition information to ensure public and employee safety, as well as to minimize the risk of consequential damage and impacts to connected EGI assets. These systems may consist of:

- **Customer-owned piping** refers to the gas piping or tubing downstream of the meter outlet tailpiece. This piping or tubing extends from the meter outlet tailpiece to customer appliances.
- **Service jumpers**: refer to a specific type of customer-owned pipe installed from an outside meter to inside the building. Its entry through the building is below-ground.
- **Customer appliances**: refer to gas appliances using gas delivered by EGI. Typical appliances include furnaces, water heaters, gas ranges and fireplaces.
- **Private downstream gas piping and sub-metering** refers to multi-use buildings with retail, condominium corporation-owned boiler rooms and emergency generators and residential ‘vertical’ occupancies where the gas piping is owned by the condo corporation. EGI supplies a customer station with a bulk meter to supply gas to all the facilitates of the multi-use building.

Customer-owned piping and appliances are designed to carry and operate on pressures ranging from pounds delivery to low pressure gas. Failure of these components can cause loss of containment and appliance malfunction, resulting in safety risk to customers and the public.

EGI must comply with *Ontario Regulation 212/01*, *clause 16 b) Supply of Gas*, which states:

> *“No distributor shall supply gas to premises unless the distributor is satisfied that the installation and use of the appliance or work comply with this Regulation and the distributor has inspected the appliance or work in accordance with a Quality Assurance inspection program.”*

EGI inspects customer-owned assets at the time of initial installation and after conducting relights. This includes inspection of appliances, supply piping, venting and combustion air systems from the customer’s transfer point. EGI ensures proper installation, correct appliance operation and no system leaks.

Warning tags and reject tags are issued to ensure that no gas-fired appliance, accessory, or equipment is left in an unsafe operating condition. There are two types of warning tags: A-tags and B-tags. A-tags are issued to identify unacceptable conditions that present immediate hazards on existing installations. A-tags are also issued when an existing B-tag has expired. B-tags are issued to identify unacceptable conditions that are not immediate hazards during both initial installation inspections and installation re-inspections. Reject tags are issued to identify unacceptable conditions that present immediate hazards on initial installation inspections.

5.4.8.1. Strategy Outcomes

The current strategy for customer-owned systems is to continue existing practices at initial installation. For any subsequent issues, the customer is responsible to take corrective action.

A sub-metering initiative with the Technical Standards and Safety Authority (TSSA) and the Sub-Metering Council of Ontario is also underway to formalize EGI’s policy and requirements on private gas piping installations with measurement systems.

5.4.9 Utilization Capital Expenditure Summary

EGI has spent an average of $35M and $49M annually in the EGD and Union rate zones respectively for the Utilization asset class. The total average capital spend is forecasted to be $57M (EGD RZ) and $60M (Union RZ) as summarized in **Table 5.4-8** and **Table 5.4-8**. The Utilization capital is further summarized as part of EGI's total five-year capital plan in **Section 6.**

Table 5.4-8: Utilization Capital Summary ($ Thousands) – EGD Rate Zone

Asset Subclass/Program Name	2021	2022	2023	2024	2025	Five-Year Forecast
Meters (Maintenance)	22,823	21,590	21,993	28,271	22,113	116,790
Meters (Growth)	9,521	9,444	10,094	9,407	9,938	48,404
Remediation	1,169	808	854	831	1,145	4,807
Regulator Refit	21,832	22,224	23,880	23,754	25,287	116,976
EGD Rate Zone Total	**55,345**	**54,065**	**56,820**	**62,263**	**58,484**	**286,978**

Table 5.4-9: Utilization Capital Summary ($ Thousands) – Union Rate Zones

Asset Subclass/Program Name	2021	2022	2023	2024	2025	Five-Year Forecast
Meters (Maintenance)	28,283	29,103	31,745	32,131	35,255	156,518
Meters (Growth)	8,823	9,080	9,906	10,027	11,003	48,839
Monitoring Systems	150	150	30	29	31	389
Regulator Refit	17,953	17,868	19,323	18,916	20,075	94,135
Union Rate Zones Total	**55,210**	**56,200**	**61,003**	**61,104**	**66,364**	**299,881**

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5.5 Storage and Transmission Operations

EGI's Storage and Transmission Operations (STO) asset classes consist of a network of natural gas assets that serve to receive, store and transport natural gas. STO assets found at EGI include compressor stations, underground storage, transmission pipelines, dehydration and liquefied natural gas (LNG) storage.

EGI's storage and transmission assets are categorized in the following asset classes:

- Compressor Stations (includes Compression and Dehydration)
- Transmission Pipelines and Underground Storage
- Liquefied Natural Gas (LNG)

EGI owns and operates 35 underground storage pools located at Dawn and nearby Tecumseh, as well as approximately 3,500 kilometres of transmission pipelines. EGI has storage and transmission assets that serve to receive, store and transport natural gas for markets in Ontario, Québec and the U.S. Northeast. EGI's Dawn Hub in southwestern Ontario is connected to most of North America's major natural gas basins, including abundant and affordable gas supplies in the Western Canadian Sedimentary Basin and the Utica and Marcellus producing regions. It is similarly connected to the major demand markets.

EGI's storage and transmission system is highly integrated, making it very attractive to customers–they can purchase gas across North America when prices are lower, store it at Dawn and have it withdrawn and delivered when and where needed. Dawn is one of the top and most physically traded natural gas hubs in North America. Much like a stock exchange, more than 100 companies buy and sell natural gas at Dawn.

EGI uses compressors to move natural gas throughout the transmission system–gas is compressed into transmission pipelines designed for high flow. Compressors are also used to move gas in and out of underground storage reservoirs by providing a significant pressure increase at the expense of flow. The use of sub-surface facilities for natural gas storage enables increased operations efficiency, conservation of produced natural gas and more effective, reliable and economic delivery to markets. These facilities are usually natural geological reservoirs such as depleted oil or natural gas fields sealed on top by an impermeable cap rock. Natural gas demand for EGI's in-franchise and ex-franchise customers varies seasonally and is greatly affected by residential heating requirements. Underground storage provides seasonal balancing for the gas supply capability versus demand requirements of EGI's customers.

The storage capability of each reservoir is determined by the reservoir's maximum operating pressure, cushion pressure and the size of the pool. Through EGI's reservoirs, the total storage working inventory is approximately 312.7 petajoules (PJ) (199.4 PJ regulated and 113.3 PJ unregulated). Each reservoir is protected by a Designated Storage Area (DSA) which is determined by EGI and approved by the OEB to protect the reservoir from exploratory drilling. The land above each reservoir is leased from landowners with storage leases.

EGI's STO assets are mainly located in southwestern Ontario and employ over 800,000 horsepower of combined centrifugal and reciprocating compression. The majority of compression capacity is split between the Corunna and Dawn compressor stations, the largest underground storage facility in Canada and a key natural gas trading hub. Dawn has interconnections to 10 major transmission pipeline systems including Vector, TransCanada Energy, Tecumseh Gas Storage and Panhandle Eastern Pipeline through the EGI Panhandle Transmission system. The two stations consist of twenty compressors with a combined total of 290,000 ISO horsepower, a major natural gas dehydration plant, station piping, large diameter valves, electrical components and other equipment required to support operations.

Dehydration assets, used primarily to manage moisture content during withdrawal, are essential to storage and transmission systems. While dehydration units can be found at various sites, the Dawn compressor station houses a major dehydration plant and associated piping, large diameter valves, electrical components and other equipment required to support operations.

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EGI operates one liquefied natural gas (LNG) facility, the Hagar station, located near Sudbury, Ontario. The Hagar station has been in operation since 1968. It is interconnected with the Sudbury lateral system, which is within the TransCanada Energy delivery area. As an integrated storage and transmission system operator, EGI requires capacity to support the integrity of the system and the provision of service to all customers–the Hagar facility provides reserve capacity that allows for operational balance and ensures reliable supply through EGI's storage, transmission and distribution systems during peak periods. The Hagar station is used to support the Sudbury area during peak periods and supply shortfalls and unplanned pressure drops or outages. The station served this purpose in 2011 during a TransCanada Energy pipeline rupture near Beardmore, Ontario.

5.5.1 Storage and Transmission Operations Objectives

The objectives for the STO asset classes are set at the system level (transmission, underground storage and LNG) to specify objectives independent for each system, as all three systems work interdependently. For example, identical compressors in the storage and transmission systems serve a different purpose, but are aligned with each system's objectives. Performance measures are identified for all system objectives. These objectives are in addition to the system integrity, reliability and compliance objectives for the Distribution Pipe, Distribution Stations and Utilization asset classes (see **Table 5.5-1**).

5.5.1.1. Transmission System Objectives

Dawn Parkway Transmission System

The Dawn Parkway Transmission System is composed of a series of parallel 26- to 48-inch diameter pipelines and compressor, metering and regulating stations running from the Dawn Operations Centre easterly toward the Greater Toronto Area (GTA), terminating at the Parkway compressor station and at the Lisgar and Albion custody transfer stations. This system has four major compressor stations (Dawn, Lobo, Bright and Parkway) to facilitate transport.

The primary purpose of this system is to transport natural gas easterly from Dawn to Parkway and to Albion. The system serves both transportation customers (gas moving between points on the system) and in-franchise regions along the route (GTA West, Southeast and portions of the Southwest regions).

Panhandle Transmission System

The Panhandle Transmission System is composed of 16-, 20- and 36-inch diameter pipelines and metering and regulating stations running westerly from the Dawn Operations Centre towards Windsor, terminating at the Ojibway River crossing where it interconnects with the Panhandle Eastern Pipeline system. Laterals which carry transmission system pressure into the Leamington/Kingsville area also form part of the system. One compressor station is used to facilitate gas movement easterly.

The primary purpose of this system is to transport natural gas from Dawn and the Panhandle Eastern Pipeline to the Windsor market gas distribution systems, serving a portion of the Southwest region. It also transports gas from Panhandle Eastern to Dawn.

Sarnia Industrial Line Transmission System

The Sarnia Industrial Line (SIL) Transmission System is composed of a series of parallel 10- to 20-inch diameter pipelines and metering and regulating stations running northerly from the Courtright stations to the City of Sarnia. An NPS 8 pipeline runs from the Dawn Operations Centre to the SIL and an NPS 20 pipeline runs from the Payne Storage pipeline to the SIL.

The primary purpose of this system is to transport natural gas from the Vector and Great Lakes pipelines at Courtright Station, DTE Energy (via St. Clair Pipelines L.P.) at St. Clair Line station, Bluewater pipeline (via St. Clair Pipelines L.P.) at Bluewater Interconnect, Dow A Pool and Dawn to the gas distribution system, serving a portion of the Southwest region.

Table 5.5-1 shows a summary of transmission system requirements and the objectives for each system.

Table 5.5-1: Transmission System Objectives Summary

Requirement	Dawn Parkway	Panhandle	Sarnia Industrial Line
Design Day Requirements	Serve the design day demand requirements of all firm in-franchise and transportation customers as modelled on design day and other days as required.	Serve the design day demand requirements of all firm in-franchise customers as modelled on design day and other days as required.	Serve the design day demand requirements of all firm and interruptible in-franchise customers as modelled on design day and other days as required.

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Requirement	Dawn Parkway	Panhandle	Sarnia Industrial Line
Transportation Requirements	Serve the transportation market between Dawn, Kirkwall and Parkway in both easterly and westerly directions as required.	Serve the Ojibway to Dawn transportation requirements as required.	Serve the transportation market between St. Clair and Dawn and Bluewater and Dawn as required.
Loss of Critical Unit (LCU)	Maintain the required LCU capability at the Dawn, Lobo/Bright and Parkway systems.	N/A	N/A
Measurement	Accurately measure all flow in and out.	Accurately measure all flow in and major stations out.	Accurately measure all flow in and flow out at major customers and pipeline interconnects.
Monitoring, Control and Operation	Monitor, operate and control transmission systems from remote control rooms at all times and in emergencies.		
Shutdowns and Outage Management	Minimize customer outage impacts during integrity work, construction activities and emergency situations. System design must allow for ongoing inspection with minimal customer disruptions.		
System Growth	System design and maintenance must consider future system growth implications.		

5.5.1.2. Underground Storage Objectives

The underground storage system is largely situated in the area surrounding the Dawn Operations Centre in Lambton County in Southwestern Ontario. Storage is split into regulated and unregulated businesses, with a total working inventory of approximately 312.7 petajoules (PJ). The annual injection and withdrawal cycle relies on compression at the Dawn and Corunna stations, on remote compression at a variety of individual storage pools and the Dawn dehydration plant. Maintenance work and capital projects are scheduled on an annual basis to meet design day and contractually firm requirements throughout the season. The objectives for the underground storage system are as follows:

- Operate and maintain 312.7 PJ of natural gas storage (199.4 PJ regulated and 113.3 PJ unregulated).
- Develop the storage system to ensure storage space is effectively and efficiently cycled. Each storage pool is designed to be filled and emptied within a prescribed timeframe to achieve the following:
  - Maximize design day deliverability to serve regulated and unregulated businesses.
  - Integrate legacy storage system operations to more efficiently fill and empty the storage system, increasing design day deliverability and reducing operating and maintenance costs.
  - Position EGI for future growth opportunities through added storage capacity and deliverability.
- Provide natural gas supply to the transmission system that meets required quality standards.

5.5.1.3. Liquefied Natural Gas System Objectives

The Liquefied Natural Gas (LNG) system's primary purpose is to supply natural gas to support the Sudbury area during peak periods and for system integrity requirements during the winter season, providing ongoing availability to meet potential shortfalls. Natural gas feedstock is converted to liquid and pumped into a tank during the off-peak summer and fall seasons. The stored LNG is vapourized back into natural gas as required during the winter season. Under full load demand, the tank carries enough inventory to supply the Sudbury market for approximately five to seven days. The objectives of the LNG System are as follows:

- Targeted full nominal capacity of 610 million cubic feet (MMcf) by December 1 annually
- Targeted daily tank vapourization capability up to 90 MMcf deliverability (for injection into the Sudbury Lateral pipeline system)
- 100% availability of any LNG balances during the winter season (typically until the end of March) net of any system integrity withdrawals and gas boil-off

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5.5.1.4. Performance Measures

The performance measures for the STO asset classes are as follows:

- Safety and environmental metric
- Number of incidents/asset ruptures
- Number of spills, orders and/or charges
- GHG emissions reduction (measured in fugitive emissions and fuel consumption reporting)
- Work management process conformance
- Direct leak assessment/leak survey results
- Capital portfolio management delivery to plan
- Reliability percentage for transmission compression
- Percentage of successful compressor starts
- Compressor availability
- Fuel consumption and maintenance costs trended against annual turnover volume
- Predicted Fuel Consumption Variance (Synergi) vs. actual variance
- Year-end Unaccounted For Gas (UFG) estimation

To achieve the STO asset class objectives, asset investment decisions are governed by the life cycle management strategies outlined in **Table 4.1-1**.

5.5.2 Storage and Transmission Operations Hierarchy

The subclass breakdown for STO is organized by system and illustrated in **Figure 5.5-1**.

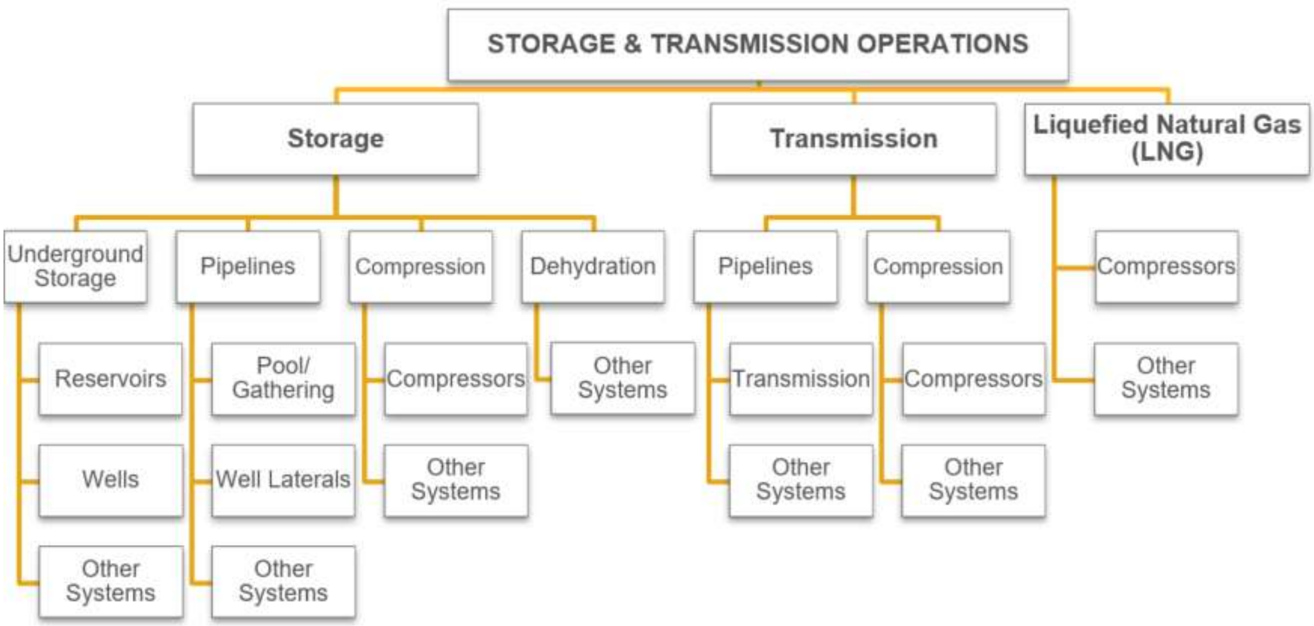

Figure 5.5-1: STO Hierarchy

Notes:

- **Compression Systems** include engine assemblies, centrifugal and reciprocating compressor assemblies, gas aftercoolers, heating and cooling systems and valve systems.
- **Other Systems** consist of the following:
  - Mechanical Systems includes components such as filters, separators, heat exchangers, fans, valves and pumps.
  - Electrical Systems includes components such as breakers, switchgear, motor control centres and lighting.
  - Safety and Controls Systems includes control valves, relief valves and fire suppression systems.
- **Pipelines** and **Underground Storage** assets include pipe, well casings and valves.

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5.5.3 Storage and Transmission Operations Asset Inventory

The asset inventory is presented in **Table 5.5-2**.

Table 5.5-2: STO Asset Inventory

Asset Subclass	EGD Rate Zone	Union Rate Zones
Compression (#)		
Compressors	15	35
Dehydration (#)		
Dehydrators	3	4
Underground Storage (#)		
Reservoirs	11	25
Wells	129	229
Pipelines (km)		
Transmission	46	1150
Pool/Gathering	60	128
Well Laterals	8	29
LNG (#)		
Compressors	N/A	3

Note: Pipe inventory is also accounted for in the Pipe asset class (see **Section 5.2.3**).

5.5.4 Storage and Transmission Operations Condition and Strategy Overview

Asset Subclass	Ave. Age (Year)	Condition	Risk / Opportunity	Maintenance Strategy	Replacement / Renewal Strategy
Compression **Dehydration** **Liquefied Natural Gas (LNG)**	30 35 50	Asset condition is primarily assessed based on a preventive maintenance (PM) program comprised of rigorous inspections. For engines and compressors, operating hours since the previous overhaul are the primary indicator of condition. Age is also considered as a condition indicator in terms of reliability and obsolescence. A reliability assessment through the Asset Health Review (AHR) was conducted on all Storage Corunna (SCOR) compressors in the EGD rate zone to determine asset condition.	Not maintaining compression, dehydration and LNG assets pose the following risks: **Operational Risk**: Potential failure can lead to equipment damage or reliability concerns. Unplanned unit failures, especially during late season withdrawal, can negatively impact customers' gas supply costs. **Employee and Contractor Safety Risk and Public Safety Risk**: The safety risk related to loss of containment from the compressor units is considered, however, the chance of a significant leak is low. Safety systems reduce the chance of an escalation even further. **Financial Risk**: Compressor failures result in unexpected repair costs and frequently involve collateral damage. New regulatory requirements could potentially limit the use of compression equipment until compliance is achieved.	The maintenance strategy for compressor, dehydration and LNG is based on a combination of Original Equipment Manufacturer (OEM) recommendations as well as the output of techniques such as Reliability-Centered Maintenance (RCM) and subject matter advisor (SMA) expertise: • Condition-based maintenance is used in many cases. A detailed inspection routine at set frequencies is established specific to a particular unit (components replaced as required). • Preventive maintenance activities are scheduled on a set frequency to restore asset performance. Condition monitoring of auxiliary equipment (pumps/motors, etc.) and control systems is ongoing.	The renewal strategies for compressors, dehydration units and LNG assets is as follows: • Overhauls as recommended by the OEM (hour-based). • Overhauls recommended by SMAs based on condition findings • Planned obsolescence based on design life and historical obsolescence (largely dependent on vendor equipment support) • Risk- and compliance-driven replacement
Underground Storage	35.5	Well condition is assessed directly by the Storage Downhole Integrity Management Program (SDIMP) using casing inspection logs. Condition assessments for wells are based on abandonment criteria prescribed by *CSA Z341* and the *Oil, Gas and Salt Resources (OGSR) Act*. Condition assessment is based on directly measured casing inspection data. Reliability modelling estimates well wall loss growth rate by extrapolating historical measured growth rate and predicting when the wall loss will exceed tolerances.	Not maintaining EGI gas wells poses the following risks: **Employee and Contractor Safety Risk and Public Safety Risk**: Loss of containment can pose a risk to public and worker safety. **Financial Risk**: Wells represent significant financial risk to EGI and regulated customers. Unexpected well failures carry a large replacement cost and incur product loss and reduced reservoir performance may drive up gas supply costs.	The maintenance strategy for gas wells is as follows: • Monitor surface and downhole well conditions to ensure the continued integrity of the storage well system including the emergency shutdown valves (where applicable), master valve, wellhead and casings. If a problem is identified, the well is repaired or abandoned. • Continue with transient pressure testing to identify wells that could benefit from acid stimulation to maintain deliverability. • Continue well inspection as per *CSA Z341* and the OGSR Act • Develop a long-term strategy for cathodic protection on well assets.	The renewal strategies for wells are as follows: • Relining wells • Replacing top two casings • Drilling new wells to replace abandoned well(s) • Wellhead and emergency shutdown valves replacement based on condition • Risk- and compliance-driven replacement
Pipelines	The overview of asset condition and strategy for transmission pipelines is discussed in **Section 5.2.4**. The overview of strategy for transmission pipelines reinforcement is discussed in **Section 5.1.4**.				

5.5.5 Compression Stations

Compressors are used in both transmission and storage systems, along with the liquefied natural gas process. Compression in the transmission system supports the function of transmission pipelines which require high flow, while in underground storage compression, it provides a significant pressure increase.

To support the transmission systems, four critical compressor stations are strategically located along the Dawn to Parkway Transmission System: Dawn, Lobo, Bright and Parkway (see **Figure 5.5-2**). Discrete blocks of compression are located at each station and used in various combinations to manage seasonal and weather-dependent system flow demands.

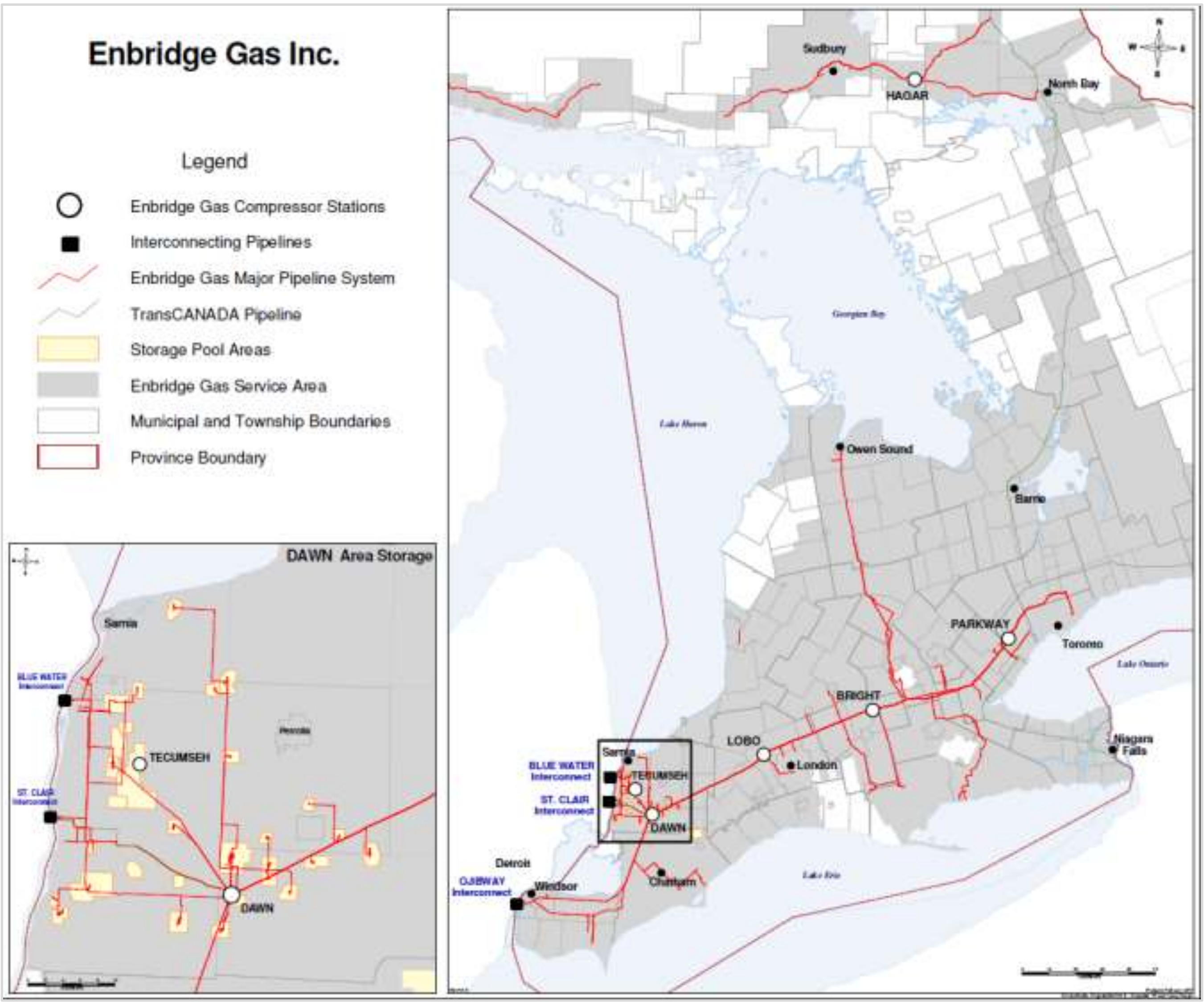

Figure 5.5-2: Compressor stations in the Dawn to Parkway Transmission System

The hub-and-spoke style storage system consists of two primary hub locations containing multiple compressor units, with the majority of compression capacity located between the Corunna and Dawn compressor stations.

All gas compressors are natural gas-fueled, comprised of both centrifugal and reciprocating (both integral and separable models) compressors, each one designed to support a specific function. Compressors vary in horsepower and consist of different vintages, makes and models. Gas compressors are designed for continuous operation, but are operated based on

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daily fluctuating system demands. Failures are influenced by service conditions (operating hours) and the design life expectancy of its components. Some key components are wear items, requiring regular inspection to establish wear tolerances and to replace as needed.

Compressor packages are comprised of several sub-systems, such as engine assemblies, compressor assemblies, valve and piping, heating and cooling, gas conditioning and ancillary equipment (such as lube oil, fuel supply and electronic control systems) which are required for the compressor to operate. Compressor packages are located throughout EGI's operating regions, including major underground storage facilities and in remote geographic areas. **Table 5.5-3** lists the inventory at each compressor station.

Table 5.5-3: Compressor Inventory and General information

Location	Number of Compressors	Notes
Dawn Compressor Station	8	Interconnects with pipelines from a number of other companies and EGI's storage system. Provides supply to the EGI transmission system and loss-of-critical-unit coverage for the Dawn Parkway System.
Lobo Compressor Station	5	Supports gas transmission from London towards Woodstock and provides loss-of-critical-unit coverage for the Dawn Parkway System.
Bright Compressor Station	4	Supports gas transmission from Woodstock towards Toronto (Parkway) on the Dawn Parkway System.
Parkway Compressor Station	2	Provides required delivery pressure and acts as a custody transfer station to TransCanada Pipelines (TCPL).
Parkway West Compressor Station	2	Provides required delivery pressure and acts as a custody transfer station to TCPL as well as loss-of-critical-unit coverage for the Dawn Parkway System.
Sandwich Compressor Station	1	Supports movement of gas from the Panhandle Eastern Pipeline system towards the Dawn compressor station.
Corunna Compressor Station	11	Supports storage injections and withdrawals. Daily winter flows are transported to market via the Dawn Parkway System. Gas is received from and delivered to Dawn and Vector pipeline systems.
Remote Storage Pool Compressor Stations	14	Supports storage injections and withdrawals. Daily winter flows are transported to market via the Dawn Parkway System.
Hagar Liquefied Natural Gas Station	2	Supports the Sudbury system during peak periods and provides additional compression as required to maintain pressure.
Iroquois Falls Compressor Station	1	Supports required delivery pressure for an industrial plant in Iroquois Falls.

5.5.5.1. Condition Methodology

Engine and compressor condition is primarily maintained through a preventive maintenance (PM) program comprised of rigorous inspections and renewals via overhauls based on manufacturer recommended intervals. As it relates to compressors, condition refers to the ability of an asset to reliably and cost-effectively perform its intended function, which can include achieving the performance expectation of the operator/owner, or providing adequate process safety measures. Gas compressors are repairable assets–asset condition can be improved through component repair or replacement, restoring asset reliability.

Between overhaul intervals, an understanding of asset condition is obtained through an inspection and maintenance program. Compressors are high-speed, rotating equipment that require constant monitoring based on rapid condition changes and failure occurrences. Control room operators provide the first line of defense by recognizing changing conditions and reacting in near real time. Online monitoring provides protection via control systems. Activities in response to the component condition or operational performance are captured in the work and asset management system. Component condition is determined using the experience and recommendations of Subject Matter Advisors (SMAs). As asset condition and performance degrade, risks are raised through the risk management process.

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For components managed via an overhaul strategy, condition is viewed as a saw tooth function (see **Figure 5.5-3)**. Condition degrades over the recommended overhaul interval and increases suddenly after an overhaul. **Figure 5.5-3** is a simplified illustration of the degradation of asset condition over the course of each interval and the function of an overhaul to restore condition to 100%. In reality, some degradation in condition occurs over the entire life of the asset that cannot be restored through overhaul activities.

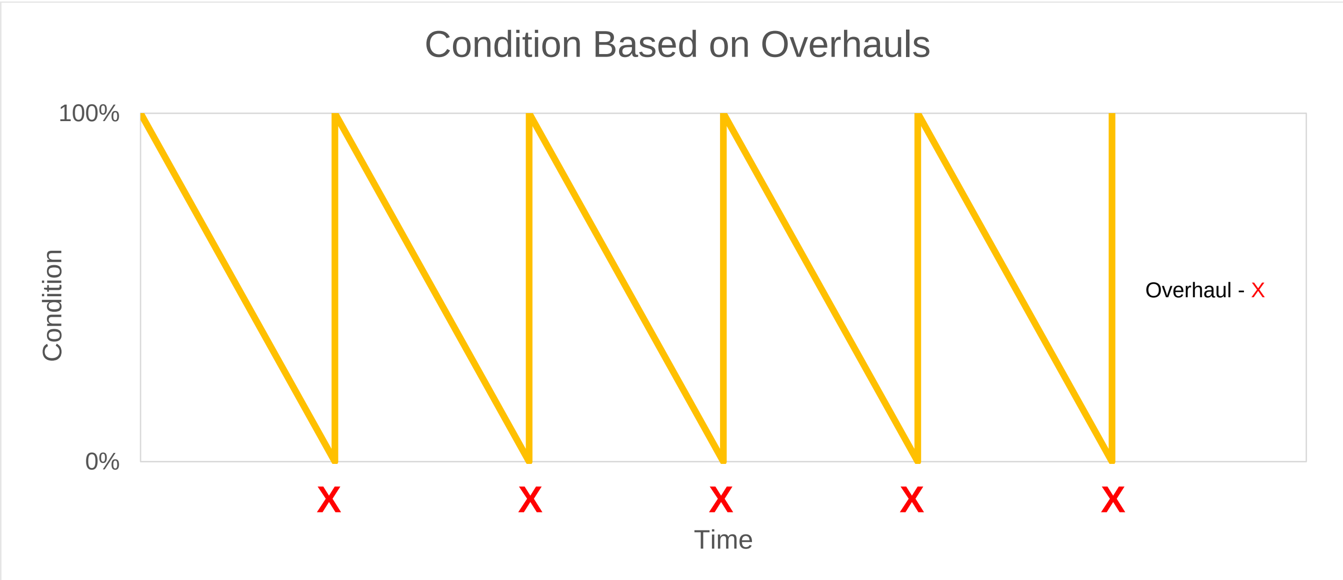

Figure 5.5-3: Condition Based on Overhauls

The overhaul schedule for compressors is based on operating hours, using the average annual usage to forecast the timing of the next maintenance activity. As weather is a factor for compression requirements during an operating season, the overhaul forecast is updated annually to reflect current operating hours and any changes to predicted annual usage. Operating hours provide the basis for planning overhaul activities, but the results of inspections may lead to the advancement or delay of an overhaul.

An Asset Health Review (AHR) was initiated for the compressors located at the Corunna compressor station. Assets were assessed based on reliability, combined with a multiplier-based, apparent condition modelling approach. Using historical maintenance data, a recurrent data analysis using statistical modelling was performed to determine the relationship between failure frequency and gas compressor operating hours. SMAs were then consulted to define and quantify the effect of failure-influencing factors. A condition status was assigned to seven key reciprocating gas compressor sub-assets, based on a conditional reliability metric (at least one sub-asset failure will occur within a 2000-hour mission time).

Condition findings are expected to be directionally informative at this time. New reliability relationship information is needed for separable compressors to apply the reliability model to reciprocating gas compressors at remote storage pool compressor stations in both rate zones. Expanding the AHR methodology to other assets such as centrifugal compressors will enhance asset health understanding for compression facilities.

Aside from scheduled preventive maintenance programs, age is also considered as a condition indicator for reliability and obsolescence. As the asset ages, vendor support declines until the risk becomes intolerable. Obsolescence poses a risk as repairs become progressively more challenging to complete. As service providers reduce support for products reaching end-of-life, the duration of an equipment outage may become extended. Asset failure under these circumstances may be unrepairable, which could pose a significant operational challenge.

Compressor stations also include yard auxiliary systems to support the primary function of the facility. Yard auxiliary systems include all piping elements (pipe, fittings, valves, regulators, boilers, pumps, air compressors, etc.) as they relate to systems like fuel gas, low point drains, atmospheric vents, compressed air, glycol supply/return, power gas, lube oil supply, potable water and fire water. The condition of yard auxiliary systems is determined using the experience and recommendations of SMAs and is assessed through routine PM inspections as prescribed by the manufacturer, through internally developed standards, or through opportunistic inspections presented during construction activities. As asset condition and performance degrade, risks are raised through the risk management process.

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Instrumentation, controls and electrical assets support many other sub-asset types and systems within compression facilities and are primarily affected by obsolescence. As condition assessment for many of these assets is not practical, the methodology for establishing condition is to consider the expected life cycle of equipment and systems and to proactively anticipate obsolescence.

5.5.5.2. Condition Findings

Overhauls are based on current run hours, forecasted annual usage and manufacturer recommended overhauls. As a result, the forecasted number of overhauls is 18 over the next five years. Asset age is considered as a condition indicator in terms of obsolescence. The age range for compressor units based on their date of installation from 2021 is shown in **Figure 5.5-4**.

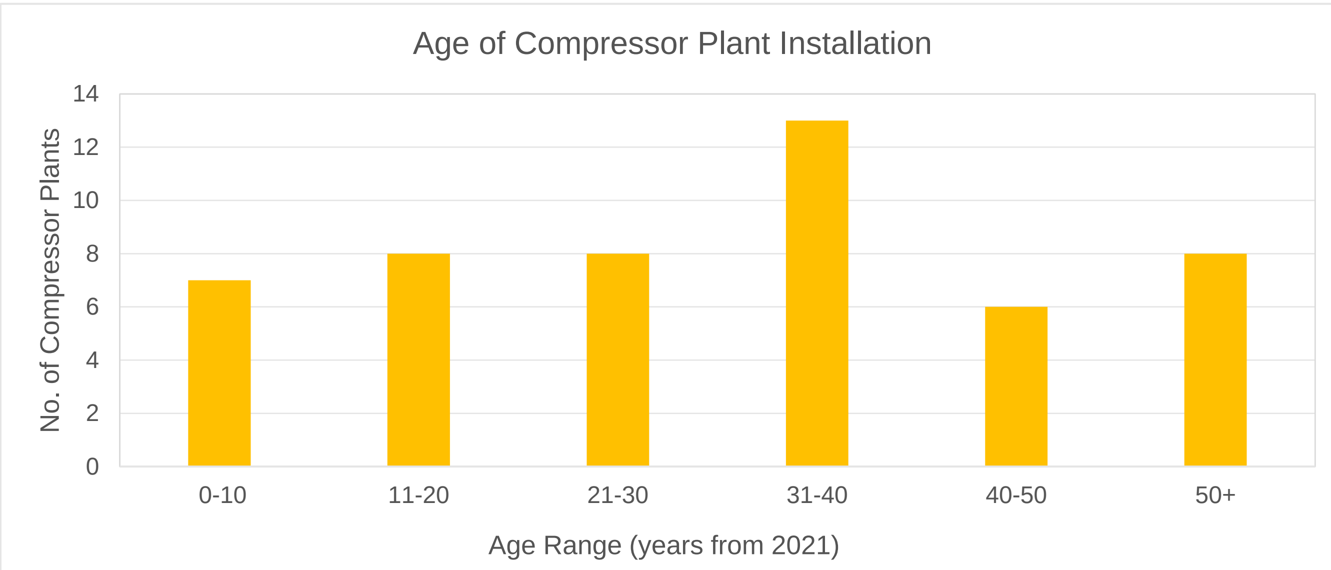

Figure 5.5-4: Age Range of Compressor Plant Installation

Previously, a gas turbine-driven centrifugal compressor was deemed as obsolete by the manufacturer and no longer supported at around 40 years old. The Dawn C compressor from the same manufacturer will be 40 years old in 2023. Using 40 years as a guideline for indicating a critical point in an asset's life, the Dawn D and Lobo A1 plants are nearing the age of 40 years. Although there has been no recent experience with non-RB211 units identifying obsolescence at 40 years, the units at Payne, Sandwich and Bickford will exceed 40 years of age within the next 10 years. The compressors at Hagar will exceed 50 years of age within the next 10 years.

Currently, five reciprocating compressors are considered at end-of-life due to obsolescence, displaying reduced reliability and increasing need for component replacement, with reduced vendor support. The five units include K701, K702 and K703 at the Corunna compressor station along with the Crowland and Waubuno compressors.

Several other compressors will be considered at end-of-life due to obsolescence over the next 10 years. Compressors K704 to K708 will all be exceeding 50 years old within the next 10 years and may experience similar reliability and parts availability issues that the K701, K702, K703, Crowland and Waubuno compressors are experiencing today.

The AHR assessment for compressors at the Corunna compressor station had the following findings and recommendations:

- Crank assemblies seem to experience an increasing misalignment rate over time. The K706 compressor has the lowest asset health compared with all other units, due to foundation issues, which resulted in a foundation replacement in 2018. Foundation issues have been identified as a degradation factor for crankshaft misalignment. Based on historical failures, the K705 crankshaft was found cracked after its foundation replacement in 2017. As the K706 compressor has been subjected to the same foundation replacement, it is recommended to monitor the K706 crankshaft regularly until the K705 cracked crankshaft root causes are identified.
- Engines on units K701, K702 and K703 have the lowest reliability and asset health and should be prioritized over other engine units if a replacement strategy is developed.

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- In general, compressors have the lowest reliability and asset health compared to other asset subclasses. As a result, compressor overhauls are required to maintain a required level of reliability.
- According to failure intensity results, glycol leaks are the major failure modes in heating and cooling systems, which seem to be a random type of event in these systems. As heating and cooling systems showed low asset health conditions in compressor stations within the EGD rate zone, an inspection and maintenance program is recommended to improve the reliability of these systems.

EGI continues to enhance its understanding of the asset health and life cycle cost for compression facilities, through the development of its Facilities Integrity Management Program (FIMP) and through the analysis of asset data captured in the work and asset management system, which inform future capital investment requirements. FIMP is currently focused on the assessment of assets within compressor facilities, not inclusive of the compressors themselves.

5.5.5.3. Risk and Opportunity

Compressors can pose a significant consequence of failure as they are integral assets required to achieve storage and transmission system deliverability requirements throughout the year. The consequence of compressor failure is dominated by gas cost impacts to customers. System risk associated with failure of a single compressor is heavily influenced by the time of year, weather severity and time to mitigate the failure.

The path to failure for critical internal wear components is generally concurrent with operating hours. If operating hours are extended too far, additional operational stress on internal components may increase the rate of replacement during overhauls. This may add significant cost to the base overhaul and increases the risk of an unexpected failure, leading to system unreliability and further cost increases.

Operational Risk: The reliability of gas compressors is integral to managing operational risk and customer impact. Unplanned failures, especially during late season withdrawal, can have a highly disproportionate impact on gas supply costs.

Gas compressor reliability risk changes continuously during annual inventory turnover. At early injection or withdrawal, compression is not required at all times to meet delivery requirements. Power requirements increase steadily and reach a maximum during late injection or late withdrawal. There is a reduced probability, in the shoulder seasons, that a single, repairable compressor failure will yield a significant consequence. Individually, each compressor asset creates a moderate operational reliability risk. Compressor outages are managed by securing gas from alternative sources at higher prices. The longer the outage, the greater the direct cost to customers. Long term outages of multiple compressors during a harsh winter can incur higher costs to customers because of the inability to meet nominations and the resulting need to purchase gas at less favorable market conditions. Short duration outages can happen regularly, however long-term outages are much less frequent.

Public Safety Risk and Employee and Contractor Safety Risk: Safety risk related to loss of containment from the compressor units is considered, however, the chance of a significant leak is low and safety systems (e.g., gas detection, flame detection, emergency shutdown) reduce the chance of an escalation (i.e., fire, explosion) even further. Associated risks are mitigated by process design, procedures and formal operator qualification and training.

Financial Risk: Financial risk is significantly mitigated by regular inspections, which then inform the necessary preventive maintenance work. A preventive maintenance program mitigates financial risk by reducing the chance of unexpected failures. Compressor failures (unplanned outages) result in unexpected repair costs (both materials and labour) and frequently involve collateral damage. The likelihood for a compressor failure to cause an event affecting non-company property and experience commodity loss is low due to mitigations within a compressor building (i.e., gas/flame detection and emergency shutdown systems).

Failure to comply with new or changing regulatory requirements could potentially limit the use of compression equipment until compliance is achieved. Restricted use of compression equipment could reduce deliverability and trigger the need to secure gas from alternate sources, at additional gas supply cost. Examples of changing regulatory requirements include:

- New federal GHG emission regulations focused on methane reductions impose new restrictions on specified fugitive and vented emission sources within EGI’s storage and transmission operations, including but not limited to compressor stations. This will include repair timelines for leaks, limits on facility venting, compressor seals/rod packing and pneumatic devices.
- There is increasing pressure to further mitigate noise levels to meet permitting requirements (such as environmental compliance approval) due to encroachment of new residential developments.

5.5.5.4. Strategy Outcomes

Detailed inspections at set frequencies, subsequent remedial activities and constant condition monitoring help identify suspect equipment conditions, reducing the likelihood of compressor failure and large-scale outages.

The renewal strategy for compression assets targets the overhaul of compressor components based on run time, inspection, condition, Original Equipment Manufacturer (OEM) recommendations and SMA review. Full replacement is generally based on design life, historical obsolescence and OEM equipment support.

Overhauls

These projects consist of the OEM-prescribed scheduled maintenance and overhauls for engines, power turbines and compressors. These overhauls satisfy the OEM recommendations to maintain equipment reliability and ensure continued asset and system reliability, aligned with 2020 Customer Engagement survey results that indicated customers are supportive of investing to maintain current levels of safety and reliability. All projects include full internal inspections and replacement of wear items to maintain reliability and reduce the risk of failure. If OEM-recommended maintenance intervals are exceeded, the risk of reduced reliability and performance increases. Regular scheduled inspections, preventive maintenance activities and machine monitoring may identify the need to perform an overhaul in advance of the OEM recommendation. Overhaul plans are based solely on operational hours and are reviewed and updated on an annual basis.

Corunna K701, K702, K703 Replacement

The obsolete K701, K702 and K703 compressors at the Corunna compressor station need to be replaced as their operating reliability is decreasing. Much of the reliability challenge stems from lean burn conversions. During the mid-1990's, the EGD rate zone embarked on an emissions abatement program, which would see all units retrofitted with low nitrogen oxide combustion systems. Lean burn (low emissions) systems were readily available for units K704 thru K710 (model KVR). The globally installed base for the KVR compressor model is large. K701 thru K703 are an earlier compressor model (KVT) with a much smaller number of units in the world. Indications from SMAs suggest that there are only four lean burned KVT units in the world and EGI owns three of them. As a result, the KVT lean burn conversion kits, which were not designed for mass production, have resulted in several reliability concerns. Reliability concerns related to these compressors translate directly into peak day deliverability risk, as all three units are needed to achieve peak day flow rates.

Corunna Meter Area Replacement

The replacement of the meter area in the Corunna compressor station is based on the risk of loss of containment, process safety and thermal expansion piping stresses. The meter area has been repurposed to perform functions it was not originally designed for, hindering further plant updates and expansion.

The existing meter area is no longer used for inventory management– it is simply the flow path used to convey gas back and forth from reservoirs. Limited cross-flow functionality is provided in the current meter area piping. This project addresses these concerns by redesigning the current meter area, installing properly-sized cross-flow functionality, pressure control and over-pressure protection and designing for the integration of additional assets.

Dawn Plant-C Compression Life Cycle

The Dawn C Plant must be replaced due to the obsolescence of a second generation RB211-24A compressor (installed in the early 1980s). Previous experience with a unit from the same manufacturer and of similar age resulted in the unit being deemed obsolete and no longer supported at about 40 years old. A similar unit was deemed obsolete and retired in 2017 due to unavailability of parts–compressor parts and components required may no longer be available.

Waubuno Compression Life Cycle

The aging storage compressor at the Waubuno station is used to inject natural gas into the Waubuno storage pool. The compressor is over 30 years old and becoming difficult to maintain. Sourcing replacement parts is difficult and continued manufacturer support is limited. To ensure a reliable storage and withdrawal service, this unit needs to be replaced to avoid a significant outage.

Crowland Station Renewal

The facility condition of the aging Crowland compressor station is considered poor. The compressor station suffers from process safety concerns, obsolescence issues, code concerns and property clearance concerns related to neighbouring buildings and the nearby rail line. The strategy includes reviewing alternatives considering future operation of storage both with and without compression.

Foundation Block Replacements

The foundation blocks for the K704 and K707 compressors at the Corunna compressor station require replacement due to age, operating hours, oil contamination and condition (the engine block foundations are deteriorating). Without remediation,

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failing foundations will allow unit settlement, creating bearing misalignments. As the frequency of bearing failures increases, the operational reliability of the unit decreases. There is also the potential for collateral crankshaft damage.

Header and Isolation Valve Replacements

The multi-year Header Valve Replacement program will address all valves on the compressor suction and discharge headers within the Corunna compressor station. The approach is to address one header per year as there can be up to 24 valves per header. Compressor station yard isolation valves that do not have sufficient seal quality to provide isolation during normal maintenance activities or emergency situations were also identified for replacement.

Leaking valve seals are not necessarily valves that leak to the atmosphere or pose a loss of containment threat. These particular valves allow gas to flow when in the closed position, posing a process safety threat, a loss of system performance by creating recycle loops and a decreased ability to provide a safe work environment for maintenance activities that require double block and bleed. These valves are sometimes used to separate piping with different MOPs. If these valves are allowed to leak, there is an increased threat of an over-pressure event at lower-pressure pipe as gas bleeds through the valve from higher-pressure pipe.

Run-to-Failure Based Programs

Several programmatic spend items are required to support operations and are planned for based on historical expenditures. Assets are identified during the year based on failures or indications that failure is imminent. Replacements are required to ensure site equipment reliability for the following:

- UPS batteries
- Lighting
- Safety and security upgrades
- Mechanical equipment

Time-based Replacement Programs

Time-based replacement is used when condition-based assessment is not comprehensive enough to identify the next failure interval. Time-based replacement is also used to proactively replace assets identified as obsolete. Targeted upgrades or replacements of control and communication assets is required to mitigate obsolescence, ensure adequate redundancy of critical systems and mitigation of emerging process safety risks. Due to the number of devices within the storage and transmission system, replacements are planned based on device types and volume.

Time-based replacement strategies are volume-driven and applied to the following groups based on obsolescence:

- Control systems (including Programmable Logic Controllers (PLCs), SCADA, Human Machine Interfaces (HMIs))
- Fire and gas detection instrumentation
- Uninterruptible Power Supply (UPS) and Motor Control Centres (MCCs)

Siemens Valve Controller Replacement

As of July 2020, Siemens will no longer support valve controllers required in the start sequence of their compressors. Three controllers service three valves on each engine skid. Each valve/controller combination is unique in operation with no redundancy. If one controller fails, it must be replaced, rendering the entire unit unavailable until replacement and set up is complete. The replacement program will replace valve controllers for two compressor plants per year through 2024.

High Performance Coating

High Performance Coating (HPC) is required on above-grade piping to reduce the chance of external corrosion. HPC has an expected life of approximately 15 years while standard coatings typically last five to eight years. HPC was recently mandated as the coating system to be used. Majority of sites only have standard coating, which is at end-of-life. Approximately 45 remote sites, four compressor facilities and one LNG facility (Hagar) with above-grade piping will be managed through this annual program.

Condition-based Replacements

Condition-based replacements are identified by detailed inspections and condition monitoring. Asset issues are raised through the work management system and risk processes, through which the appropriate treatment is determined and may result in a maintenance expenditure. Many of the discrete investments within the portfolio are identified and planned using this approach.

As EGI develops its risk management and process safety management practices, the company intends to perform periodic condition assessments at critical facilities. Although the plan for the Facilities Integrity Management Program (FIMP) is under development, there are several aging facilities that provide critical infrastructure support to Storage and Transmission Operations. A more comprehensive understanding of the condition of these facilities will support risk management and the decision process. As the risk assessments are completed and the long term needs for Storage and Transmission are assessed, EGI will develop maintenance and replacement strategies to balance performance, risk and cost. Some specific sites where risk assessment is anticipated in the coming years are Corunna, Crowland and Hagar.

5.5.5.5. Capital Expenditure Summary

The summary of Compression projects and programs under the Compressor Stations asset class is described in **Section 5.5.6.5**.

5.5.6 Dehydration

Integral to Storage and Transmission, dehydration facilities remove moisture from natural gas as it is taken from underground storage. This ensures that gas entering the transmission and distribution system meets the contractual standard of moisture content and avoids operational problems related to high moisture content. Natural gas in combination with water, when cooled, can form methane hydrates that can plug valves, fittings or even pipelines. The dehydration process involves contact between the natural gas and liquid glycol streams to remove excessive moisture from the natural gas stream. The resultant output natural gas helps to ensure pipelines are dry and customer quality specifications for moisture content are met. EGI is obligated to meet a gas quality specification (moisture content) of 4 lbs H20/MMscf, as set out in *C1 & M12 Tariffs & Interconnect Operating Agreements*.

5.5.6.1. Condition Methodology

Dehydration systems are comprised of mechanical, rotating, electrical and control system equipment similar to compression auxiliary equipment. The maintenance strategies for dehydration facilities are based on the same inspection methodologies as compression (see **Section 5.5.5.1**).

5.5.6.2. Condition Findings

Dawn Hub Send-out Gas Quality
The Dawn Hub operation blends multiple sources of supply on a daily basis. As such, the Dawn send-out moisture content is dependent on the daily supply balance of upstream supplies (i.e. Vector/Great Lakes) and storage supplies and their respective moisture content to meet gas quality requirements. Through assessment of contractual moisture content obligations of interconnecting pipelines and modelled moisture content, it is expected that incremental dehydration facilities will be required to ensure EGI is able to reliably serve firm customer demands. In meeting current supply obligations, the following is considered:

- EGI's ability to operationally blend multiple sources of supply from upstream pipelines and the storage system to ensure the safe and reliable delivery of natural gas and meet contractual obligations
- Assessment of contractual moisture content obligations of upstream supply sources to the Dawn Hub (e.g. DTE Energy, Bluewater, Panhandle Eastern Pipeline, Vector and Great Lakes pipeline systems)
- Design day storage inventory levels by pool and the expected moisture content of the pools on design day

Tanks
Installed in 2005, the Dawn dehydration process tank is a 92,000-litre buried fibreglass single wall tank with a blanket gas system. External pressure on the tank wall could lead to cracking and undetectable small tank leaks.

Process Controls

SMAs have not identified condition concerns related to existing automated dehydrators and incinerators at this time. The Chatham D and Crowland stations lack remote automation of the dehydration and incinerator systems, creating a process safety concern that could experience an undetected failure.

5.5.6.3. Risk and Opportunity

Although a detailed risk analysis has not yet been completed to address Dawn gas quality concerns, it is believed this is a significant risk to the ability to supply gas at quality levels that ensure safe and reliable service to customers. A risk assessment will be completed to validate understanding of the issue and timing requirements.

Operational Risk: Inability to maintain EGI obligation of 4 lbs H20/MMscf under the *C1 & M12 Tariffs and Interconnect Operating Agreements* can impact firm service to all distribution customers, the storage and transmission system and third-party storage providers. A number of dehydration systems at remote storage locations are also being considered for upgrades or abandonment due to obsolescence or legacy designs.

Environmental Risk: Dehydration systems could experience a failure that would result in a spill of triethylene glycol to the environment. The likelihood is greater at manually-operated locations and in systems containing single-walled tanks.

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Financial Risk: Inability to maintain EGI's obligation of 4 lbs H20/MMscf under the *C1 & M12 Tariffs and Interconnect Operating Agreements* may result in financial consequences if market supply needs to be replaced in a limited market or in the event of potential revenue loss, as well as damage claims from customers.

5.5.6.4. Strategy Outcomes

Detailed inspections at set frequencies, subsequent remedial activities and control room condition monitoring help to identify suspect equipment condition, reducing the likelihood of failure and large scale outages.

The replacement strategy for dehydration assets is proactive replacement that targets equipment based on condition and obsolescence. This strategy is generally dependent on OEM support. The goal of this strategy is to proactively replace or rebuild station components prior to end-of-life to reduce risk and maintain a safe and reliable dehydration system, aligned with 2020 Customer Engagement survey results which indicated customers are supportive of investing to maintain current levels of safety and reliability.

The maintenance and replacement strategy for dehydration includes:

Replacements

The condensate process tank at the Dawn dehydration plant must be replaced with a double-walled tank with the capability to identify a breach of either the inner or outer wall. The Dawn dehydration motor control centre (MCC) requires replacement due to obsolescence.

Improvements

Upgrading dehydration controls at the Chatham D plant and connecting to existing remote I/O devices at the incinerator provides remote visibility and automation capabilities. Similar upgrades are planned for the Crowland station.

Dehydration Expansion

This project will conduct a risk assessment of the Dawn Hub send-out gas quality and provide recommendations. Based on SMA input, it is forecasted that incremental dehydration capacity may be required for Winter 2023-2024 at either the Dawn or Corunna compressor stations.

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5.5.6.5. Compressor Stations Asset Class Capital Expenditure Summary

EGI has spent an average of $12M and $137M annually in the EGD and Union rate zones respectively for the Compression Stations asset class. The total average capital spend is forecasted to be $86M (EGD RZ) and $45M (Union RZ) as summarized in **Table 5.5-4** and **Table 5.5-5**. Storage and Transmission capital is further summarized as part of EGI's total five-year capital plan in **Section 6.**

Table 5.5-4: Compression Stations Asset Class Capital Summary ($ Thousands) – EGD Rate Zone

Program/Project Name	2021	2022	2023	2024	2025	Five-year Forecast
Growth	**5,005**	**27,707**	**16,421**	**1,637**	**-**	**50,769**
Dehydration Expansion	5,005	27,707	16,421	1,637	-	50,769
Replacements	**12,901**	**11,808**	**19,031**	**218,759**	**8,179**	**270,678**
SCOR: K701/2/3 Reliability - Replacement	-	973	11,924	214,088	4,089	231,083
Overhauls	**586**	**900**	**487**	**-**	**430**	**2,403**
Integrity	**61**	**61**	**64**	**62**	**66**	**314**
Improvements	**27,528**	**34,196**	**23,312**	**11,328**	**8,554**	**104,918**
SCOR: Meter Area-Upgrade	18,717	22,971	-	-	-	41,688
SCRW: Station Renewal In-Place	-	6,848	15,605	6,840	6,090	35,383
EGD Rate Zone Total	**46,081**	**74,672**	**59,315**	**231,786**	**17,229**	**429,082**

Table 5.5-5: Compression Stations Asset Class Capital Summary ($ Thousands) – Union Rate Zone

Program/Project Name	2021	2022	2023	2024	2025	Five-year Forecast
Replacements	**4,253**	**23,688**	**92,672**	**69,711**	**7,133**	**197,456**
Dawn Plant-C Compression Life Cycle	-	19.730	89,413	51,421	5,603	166,167
Waubuno Compression Life Cycle	-	-	1,113	14,507	643	16,263
Siemens Valve Controllers Replacement	-	974	1,027	1,006	-	3,006
Overhauls	**298**	**4,485**	**3,601**	**152**	**2,976**	**11,512**
Integrity	**1,531**	**684**	**722**	**706**	**750**	**4,393**
High Performance Coating	565	562	593	581	616	2,917
Land Structures and Improvements	**1,530**	**734**	**454**	**463**	**224**	**3,405**
Improvements	**1,682**	**2,872**	**733**	**397**	**627**	**6,311**
Union Rate Zones Total	**9,293**	**32,463**	**98,181**	**71,429**	**11,710**	**223,076**

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5.5.7 Underground Storage

The use of subsurface facilities for natural gas storage allows for increased efficiency in operations, conservation of produced natural gas and more effective and economic delivery to markets. Natural gas is stored in depleted oil or natural gas fields sealed on the top by an impermeable cap rock.

Wells are used to inject into and withdraw natural gas from underground storage reservoirs and to monitor reservoir pressure. EGI well assets consist of 129 and 229 wells in the EGD and Union rate zones respectively. This includes natural gas storage wells and observation wells.

EGI's storage wells are located primarily in agricultural areas. **Figure 5.5-5** displays the ages of EGI well assets by drilling date (the original well construction date). **Figure 5.5-6** shows well age based on production casing (the innermost casing) age. A well's production casing age indicates a new casing was added to the well to improve its integrity, an effective method for extending its life.

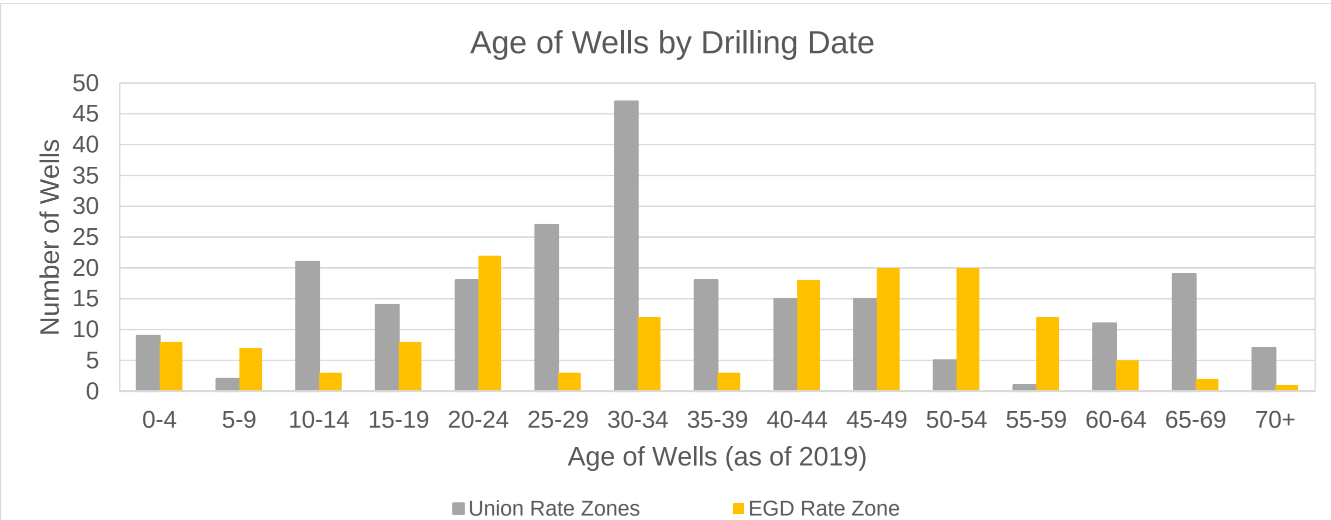

Figure 5.5-5: Age of Wells by Drilling Date

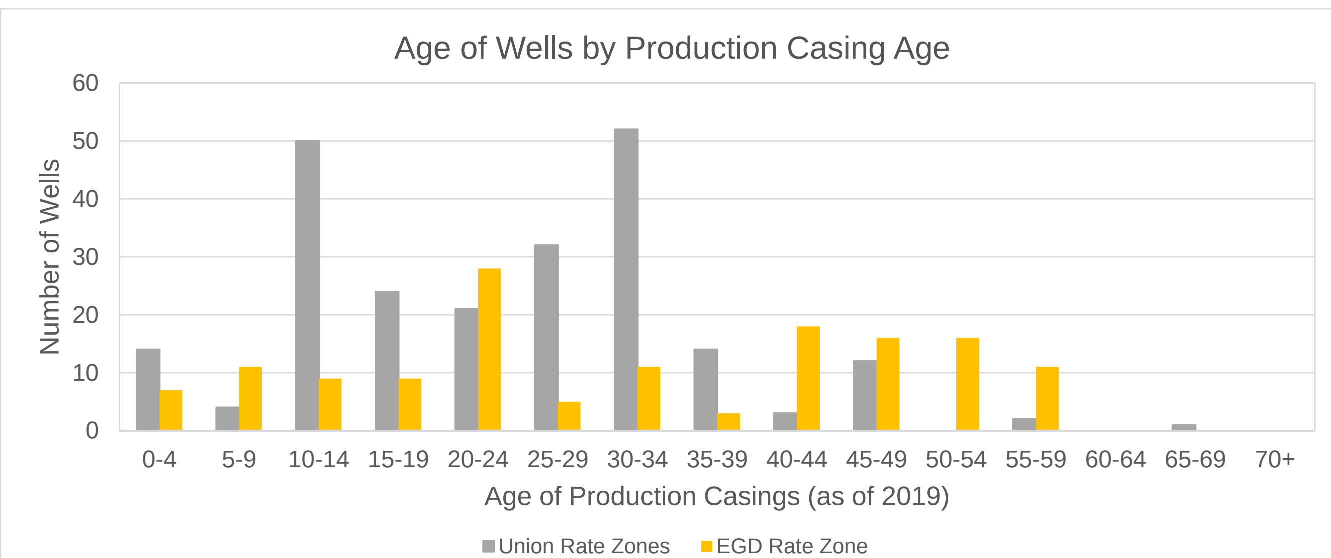

Figure 5.5-6: Age of Wells by Production Casing Age

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Degradation of well assets is generally experienced as casing wall loss. Wall loss can be internal or external and can be caused by factors such as mechanically induced damage during drilling operations or corrosion influenced by various geological layers and subsurface fluids. As wall loss progresses, previously insignificant defects become more pronounced. For newer wells, the number of well casing defects requiring action is expected to be low.

The top two joints of well casing (approximately the top 20 meters from the surface) can be repaired. These repairs, known as casing back-offs, result in the removal of a short section of old casing and replacement with new casing, extending the well's life expectancy.

Replacement of casing below the first 20 meters becomes difficult - primary options are relining or abandonment. Relining is performed by inserting a new smaller diameter production casing inside the affected casing and filling the annular space with cement. Abandonment is performed by filling the wellbore with cement and removing it from service. Relining and abandonment may be followed by the drilling of new wells to restore lost deliverability.

5.5.7.1. Condition Methodology

Well condition is assessed by the Storage Downhole Integrity Management Program (SDIMP) using casing inspection logs (similar to in-line inspection tools used for pipelines). Well casing inspection logs are completed per *CSA Z341*. The logging tool is based on magnetic flux leakage (MFL) technology that infers changes in pipe wall thickness. As per code, a baseline casing inspection log is run on the production casing of all new wells drilled (and when a well is relined with a new production casing). *CSA Z341* stipulates that wells receive their second casing inspection log five years after the baseline log. Subsequent inspection frequencies depend on wall loss and the growth rate of metal loss features.

Following each casing inspection log, the minimum yield pressure of the production casing and the corrosion growth rate (the percentage of metal loss per year) are calculated based on the maximum wall loss detected by the casing inspection log. Based on calculation results, the next inspection date is required in five or 10 years. However, if the minimum yield pressure of the production casing is less than maximum operating pressure of the storage zone (or if a pressure test fails), the well will either be relined to continue its operation or removed from service. New wells would be required to restore the lost deliverability from the well abandonment.

5.5.7.2. Condition Findings

A condition model has been developed to predict the end-of-life for each storage well as shown in **Figure 5.5-7**. Condition assessment is based on data collected from casing inspection logs. The model estimates the corrosion growth rate by extrapolating the historical measured growth rate and predicting when the corrosion will exceed an acceptable limit. The acceptable limit is defined by *CSA Z341* and will trigger remediation or abandonment to ensure well integrity.

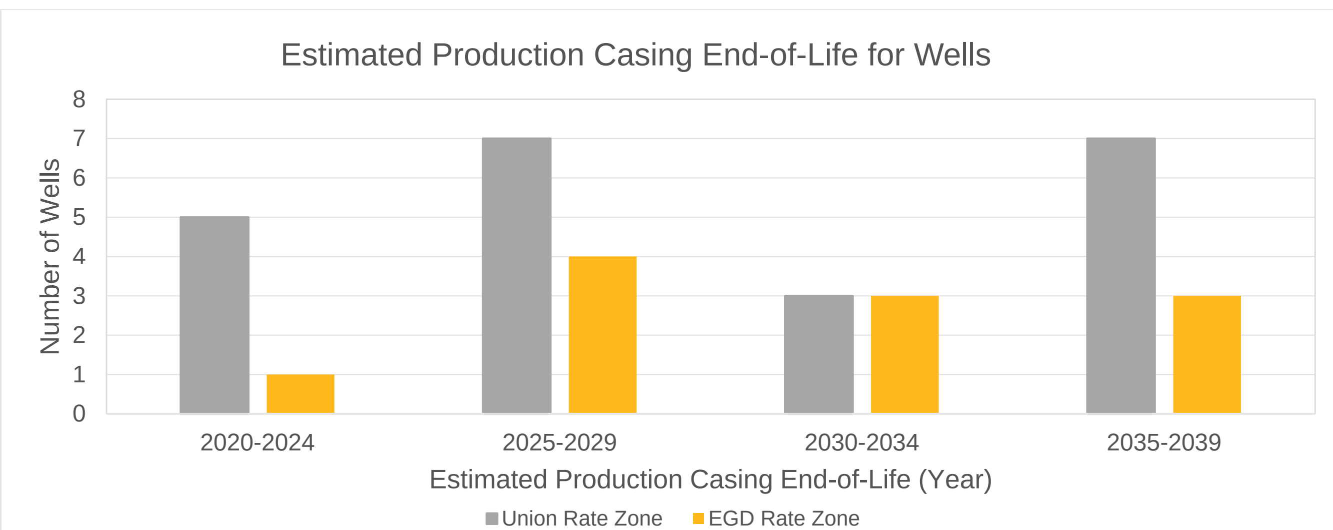

Figure 5.5-7: Estimated Production Casing End-of-Life for Wells

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The condition model considers factors such as:

- Previous condition from the most recent casing inspection
- Rate of corrosion growth over multiple casing inspections
- Accuracy of casing inspection technology used during previous inspections. Note that inspection technology has become more accurate over time and may affect projections.

It should be noted that as more inspection data is obtained, these estimates are expected to change. EGI transitioned to high-resolution casing inspection log technology in 2009. The first high resolution well logs showed that previously reported metal loss features were reduced in many instances. Furthermore, as technology evolves and more field data is obtained, data quality interpretations continue to improve and metal loss features may differ over repeated logs. As new data is loaded into the model, end-of-life projections are expected to change. When a well's production casing reaches end-of-life, evaluations are conducted to determine whether the well should be relined or abandoned. Activities to restore lost system deliverability are also performed, which may include the drilling of a new natural gas storage well.

In addition to the above estimated casing mitigation actions, the following findings require investments that will support the safety and reliability expectations for underground storage assets:

Wellhead Upgrades

EGI inspects and evaluates the condition of its wellheads on an ongoing basis, including wells grandfathered under previous versions of *CSA Z341*. Through this work, several wellheads were identified to be updated based on CSA code changes. Since 2002, *CSA Z341* specifies that all connections above the casing bowl shall have flanged connections, as threaded connections are more prone to leaks and have a higher failure rate. In addition, *CSA Z341* no longer allows the pressure rating of the wellhead to be de-rated based on the pressure rating of the master valve. Five wellheads were identified as having threaded side-ports on the intermediate spool section. EGI has established that it will no longer allow threaded connections or pressure de-rating on any storage well.

Well Testing

The deliverability of natural gas storage wells declines over time, associated with the normal operation of the storage pools. Deliverability and transient pressure testing are conducted annually at selected storage wells to assess well deliverability, identify any decline in deliverability and to assess the likelihood of whether well stimulation can recover any deliverability losses.

Well deliverability and pressure transient testing is conducted on selected wells following the fall and spring stabilization period. Wells are individually tested over 72 hours with fixed flow-rate and shut-in periods. Well pressures and flow rates are recorded and the data is used to determine reservoir properties, wellbore damage and well performance. Well performance is compared with previous tests to quantify any deliverability loss. Wells are also selected for acid stimulations. Retesting occurs approximately every 10 years depending on pool operational demands and maintenance requirements.

Well Security and Accessibility

Approximately 20% of wells are in areas where personnel access is limited. These wells are often in the middle of an agricultural field and, at the request of the landowner, laneways were not installed. During normal maintenance activities, personnel are required to access these wells, exposing them to difficult physical conditions. Working with landowners, investments are required to install laneways and facilitate personal access to these wells for essential maintenance activities.

The largest risk to storage wellheads is farm traffic. Each wellhead is surrounded by a chain link or metal post fenced area. Based on the results of a risk assessment, EGI has installed four pre-cast concrete blocks around each fenced area in the EGD rate zone to reduce or eliminate any impact to the wellhead by farm equipment. This program will install pre-cast concrete blocks around all wellheads in agricultural areas where practical.

Cathodic Protection

Wells in the Union rate zones have cathodic protection installed at each storage field for protection; wells in the EGD rate zone are not similarly protected. EGI is in the process of studying the benefits of cathodic protection to develop a strategy for underground storage assets.

Crowland Storage Pool

The Crowland storage pool in the Niagara region is used to balance natural gas demands in the local market. The pool has 16 natural gas storage wells and eight observation wells for pressure monitoring. Since amalgamation, the flow capability of the pool has been assessed through deliverability testing. Evaluations are being completed on local market options that may simplify the operation of the pool if sufficient market demand is available in the local distribution market. An integrity assessment for each well is required to determine if existing wells can be upgraded or will need to be abandoned. Replacement wells may be required depending on the outcome of the assessment.

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A1 Observation Wells

Observation wells are used to monitor the pressure in natural gas storage pools and do not cycle gas in and out of the reservoir. Each pool has an official Guelph observation well that monitors the pressure of the Guelph reef formation where gas is stored. However, many pools have a tighter secondary formation where gas can migrate, known as the A1 Carbonate formation. A1 observation wells are used to monitor the movement of gas in and out of the A1 Carbonate formation. The gas in the formation is contained within the reservoir but may not be accessible working gas that can be cycled on an annual basis. As gas is less accessible in this formation and requires the pool pressure to be lowered before migrating back to the Guelph reef, observation wells are required to be incorporated into the storage facility in accordance with *CSA Z341*.

The A1 observation wells are used as a tool in storage pool material balance studies. Biannually, storage pools are stabilized and the Guelph pressure is used to calculate an inventory based on pressure. This is then compared with the pool's metered inventory and variances above a certain threshold are investigated. In some instances, gas movement into the A1 Carbonate formation contributes to these variances. An A1 observation well can confirm this issue and assist with explanations and potential adjustments to pool size and inventory. For effective inventory management, one or more A1 observation wells are required to monitor the gas in the A1 Carbonate formation. Pools that do not have A1 Carbonate wells will be targeted for the addition of an observation well.

5.5.7.3. Risk and Opportunity

Currently, measured condition data is obtained through the Storage Downhole Integrity Management Program (SDIMP), which currently indicates that well abandonments will be required over the duration of the program.

Safety Risk: If unmitigated, risks related to safety are generally expected to increase slowly due to continued corrosion. Wells exceeding corrosion tolerances will be abandoned as prescribed by code, proactively reducing significant safety risks. Risk modelling considers the possibility of injury to the public and personnel, as these assets have a major influence on public and employee safety risk. Wells have the potential to cause injury during a loss of containment event.

Financial Risk: If unmitigated, loss of containment risks are generally expected to increase slowly due to continued corrosion. Risk modelling considers loss of containment and damage to infrastructure. However, the probability of failure is generally very low. Wells represent significant financial risk to EGI and regulated customers. Unexpected well failures carry a large cost of replacement and lost product.

Well abandonment is a safety and financial risk mitigation of the existing wells. However, once an existing well is abandoned, the flow capacity of the associated reservoir is reduced. Reduced reservoir may reduce storage deliverability, which could require that gas supply be obtained from other potentially more expensive sources. Risk reduction is achieved by drilling new wells to replace those that have been abandoned. Well failures, especially during late season withdrawal, can have a highly disproportionate impact on gas supply, requiring gas to be obtained from other potentially more expensive sources. A single well failure can shut down an entire reservoir for a long duration.

The operational reliability consequences of an unexpected well failure can be significant for regulated customers. Such a failure could cause a decrease in gas supply, requiring gas to be obtained from other potentially more expensive sources to regulated customers, as a portion of required gas would need to be sourced from other suppliers for the entire duration of the event. Consequences may be moderate because other reservoirs continue to operate if a single reservoir experiences an outage.

Well-related activities are targeted to reduce or explain unaccounted for gas (UFG). UFG is a contributor to gas supply costs to regulated customers. Activities intended to reduce UFG provide a positive benefit to EGI's customers.

5.5.7.4. Strategy Outcomes

The capital maintenance and renewal programs for underground storage wells are as follows:

Well Casing Inspection and Maintenance

As part of the life cycle management strategy, well condition is continually assessed to determine condition and develop mitigation plans, as per *CSA Z341* and the *Oil, Gas and Salt Resources (OGSR) Act.* Projections of well life expectancy are updated as new inspections are completed and additional operational data is obtained. Remediation is performed on wells on a case-by-case basis through either relining or abandonment to ensure the safe and reliable operation of EGI's underground storage systems. This is aligned with 2020 Customer Engagement survey results where customers are supportive of investing to maintain current levels of safety and reliability.

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Wellhead Upgrades

A multi-year plan has been developed to replace wellheads with threaded connections and wellheads that have been de-rated based on their master valve rating. EGI is also planning to install emergency shutdown valves on all storage wells, a long-term goal supported through capital investment.

Well Testing and Acid Stimulations

Based on the results of annual well testing program, wells are stimulated with acid to mitigate lost deliverability. Well testing can confirm the magnitude of lost deliverability and whether acid stimulation can recover deliverability.

An activity testing and stimulation program for wells has been in place for the Union rate zones over the past fifteen years. Most wells in the EGD rate zone have not been stimulated and additional well testing data is required. The program focus will shift to conducting initial acid stimulations for wells in the EGD rate zone, which will also need to be tested to determine current performance coefficients, lost deliverability and reservoir properties. The program will return to a system-wide focus once these activities have been completed.

Well Accessibility

Where EGI is able to come to an agreement with landowners, laneways will be constructed to improve access to wells that currently do not have laneways. Capital will be required to install proper laneways on these wells.

Cathodic Protection

Actions taken on cathodic protection will be dependent on the outcome of the cathodic protection study on storage wells. Increased capital may be required to add or modify cathodic protection on storage wells in the EGD rate zone.

Crowland Storage Pool

The current scope of the Crowland Wells Upgrade project includes the installation of two new horizontal wells, an observation well and new wellheads and master valves to 16 existing storage wells and eight observation wells. Additional integrity assessments are underway to confirm existing well condition and anticipated deliverability of any new wells.

A1 Observation Wells

The Corunna and Ladysmith storage pools do not currently have A1 observation wells. The Coveny storage pool also requires a new A1 observation well. Regional geology and past studies suggest there is a potential for gas to be migrating into the A1 Carbonate formation at these storage pools. A new A1 observation well will be drilled to confirm the movement of gas into the A1 and used to support inventory material balance studies in the future. This may result in adjustments to pool inventory or size.

EGI continues to enhance its understanding of asset health and life cycle cost for wells, which will inform future capital investment requirements.

5.5.7.5. Capital Expenditure Summary

The summary of Underground Storage projects and programs under the Transmission Pipe and Underground Storage asset class is described in **Section 5.5.8.5**.

5.5.8 Transmission Pipelines

Pipeline assets are a critical component of the storage and transmission operations and transport gas between custody transfer points, distribution networks, as well as storage gathering systems. Pipelines are categorized in three asset subclasses:

- **Transmission pipelines** connect compressor stations to custody transfer points or other transmission pipelines and distribution networks and generally operate at or above 30% Specified Minimum Yield Strength (SMYS).
- **Pool/Gathering pipelines** connect compressor stations to reservoirs. Multiple reservoirs can be connected to a single compressor station by individual pool pipelines. The central collection lines that interconnect wells within a reservoir, gathering lines, are generally larger diameter pipe – matching the size of the associated pool pipeline to collect and distribute gas to smaller well laterals.
- **Laterals** connect individual wells to a gathering pipeline. Laterals are generally NPS 10 pipe. In some cases, more than one well is connected to a single branch connection extending from the gathering pipeline.

The largest operational threat to the storage pipeline system is internal corrosion/erosion due to entrained reservoir liquids and solids. Third-party damage is also a significant threat due to annual installation of agricultural drain tile by landowners. Note that third-party damage potential has diminished with Ontario One Call legislation.

Pipelines are inspected regularly for leaks, depth of cover and effectiveness of the cathodic protection system. Aerial inspections are also performed. The system is monitored for changes in area class location due to encroachment.

5.5.8.1. Condition Methodology

See **Section 5.2.5.1** for the condition methodology of Pipe assets.

5.5.8.2. Condition Findings

See **Section 5.2.5.2** for the condition findings of Pipe assets. Specific findings for the following assets are also noted:

Panhandle Line Replacement

- The river crossing pipelines cannot be inspected using in-line inspection (ILI), but their age infers that the pipe condition could be degrading.
- Other challenges related to the pipe construction method make it unlikely that current technologies can provide usable data to improve decision-making.

Dawn-Cuthbert

The section of NPS 26, NPS 34 and NPS 42 pipelines leaving Dawn toward the Cuthbert station (one kilometre away) cannot be inspected using in-line inspection(ILI). The current technique for inspecting these sections is external corrosion direct assessment (ECDA) which provides important information when no other option is available. However, to thoroughly inspect these pipelines, ILI is internally accepted as the required level of diligence for direct assessment of >30% SMYS pipe.

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5.5.8.3. Risk and Opportunity

See **Section 5.2.5.3** for risks and opportunities of Pipe assets. Specific risks and opportunities for the following assets are also noted:

Panhandle Line Replacement

The principal risk is the lack of ILI data needed to inform effective decision-making to mitigate a potential loss of pipeline containment (leak). Replacement of the river crossing pipelines with a new single pipeline, designed, manufactured and constructed to current standards that is ILI-capable can address this risk.

Dawn-Cuthbert

Any gas release of a >30% SMYS pipeline can result in significant risk to public safety and may require a substantial emergency response and temporary shutdown. The Dawn-Cuthbert pipeline segments are highly critical assets which carry a significant portion of the capacity on the Dawn Parkway System. The absence of inline inspection data creates challenges in appropriately managing the risk of these highly critical pipeline segments.

5.5.8.4. Strategy Outcomes

Refer to **Section 5.2.5.4** for more details on the TIMP strategy for pipe assets. Projects for the following assets are also noted:

Panhandle Line Replacement

EGI is investigating the replacement of two NPS 12 river crossing pipelines installed in 1947. A potential replacement would be a single pipeline and would be designed, manufactured and constructed to current standards and would be in-line inspection capable.

Dawn to Cuthbert

Three sections of pipe (NPS 26, NPS 34 and NPS 42) each 800 metres in length, located between the Dawn facility and the Cuthbert metering station, cannot be inspected using ILI tools. This project will involve installing ILI launchers and receivers within the Dawn facility and performing existing line retrofits to remove restrictive fitting or pipe configurations, which will allow for the pipeline segments to be in-line inspected with a targeted in-service date of late summer 2022.

5.5.8.5. Transmission Pipe and Underground Storage Asset Class Capital Expenditure Summary

EGI has spent an average of $8M and $85M annually in the EGD and Union rate zones respectively for the Transmission Pipe and Underground Storage asset class. The total average capital spend is forecasted to be $12M (EGD RZ) and $113M (Union RZ) as summarized in **Table 5.5-6** and **Table 5.5-7**. Transmission Pipe and Underground Storage capital is further summarized as part of EGI's total five-year capital plan in **Section 6.**

Table 5.5-6: Transmission Pipe and Underground Storage Capital Summary ($ Thousands) – EGD Rate Zone

Asset Subclass/ Program Name	2021	2022	2023	2024	2025	Five-Year Forecast
Replacements	**3,898**	**6,557**	**4,850**	**9,918**	**2,311**	**27,535**
PCRW: Wells-Upgrade	-	-	-	552	1,706	2,258
Land/Structures Improvements	**300**	**226**	**1,456**	**82**	**87**	**2,152**
Integrity	**5,719**	**5,687**	**3,077**	**8,059**	**1,619**	**24,161**
Improvements	**2,620**	**2,068**	**762**	**635**	**785**	**6,870**
EGD Rate Zone Total	**12,537**	**14,538**	**10,145**	**18,695**	**4,803**	**60,719**

Table 5.5-7: Transmission Pipe and Underground Storage Capital Summary ($ Thousands) – Union Rate Zones

Asset Subclass/ Program Name	2021	2022	2023	2024	2025	Five-Year Forecast
Replacements	**14,288**	**14,561**	**39,629**	**13,562**	**10,664**	**92,705**
Panhandle Line Replacement	-	1,971	31,789	4,266	-	38,026
Growth	**30,405**	**210,494**	**11,406**	**127,364**	**5,218**	**384,888**
Dawn Parkway Expansion Project (Kirkwall-Hamilton NPS 48)	-	208,225	6,386	-	-	214,611
Sarnia Expansion (Novacor Station)	7,853	42	-	-	-	7,894
Sarnia Expansion - Bluewater Energy Park (Asset #1)	344	343	3,053	73,668	3,923	81,331
Sarnia Expansion - Bluewater Energy Park (Customer Station)	-	12	41	14,100	628	14,782
Sarnia Expansion - Bluewater Energy Park (Asset #2)	-	609	1,926	39,596	667	42,797
Sarnia Expansion (NPS 20 Dow to Bluewater)	22,208	1,264	-	-	-	23,472
Land/Structures Improvements	**140**	**140**	**147**	**144**	**-**	**572**

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Asset Subclass/ Program Name	2021	2022	2023	2024	2025	Five-Year Forecast
Integrity	**7,948**	**40,064**	**9,341**	**13,607**	**12,840**	**83,800**
Dawn - Cuthbert - ECDA to ILI Retrofit NPS 42, 34, 26	1,223	28,721	-	-	-	29,944
Improvements	**306**	**714**	**565**	**525**	**567**	**2,677**
Well Optimization Program	306	304	321	314	334	1,579
Wellhead Upgrades	-	393	342	297	-	1,032
Union Rate Zones Total	**53,087**	**265,975**	**61,089**	**155,202**	**29,289**	**564,642**

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5.5.9 Liquefied Natural Gas (LNG)

Hagar Station is EGI's liquefied natural gas (LNG) storage facility, located near Sudbury, Ontario (see **Figure 5.5-8**). The station serves to provide reserve capacity and balance operational loads during peak periods throughout the storage, transmission and distribution systems, ensuring system integrity and gas supply reliability.

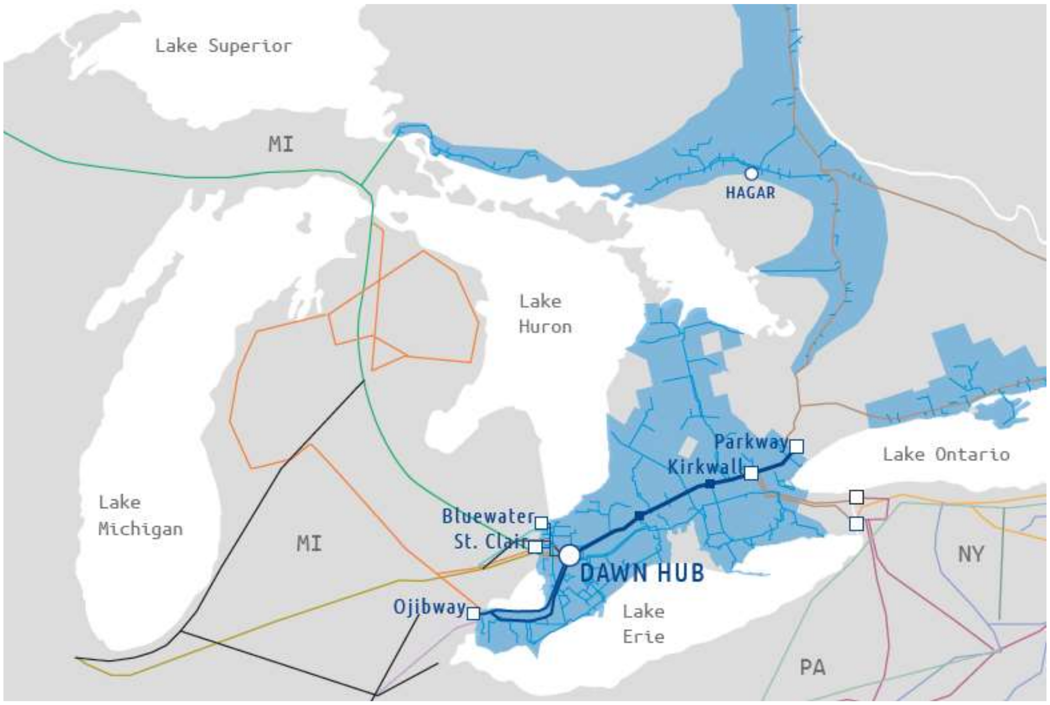

Figure 5.5-8: Hagar LNG Station Location

5.5.9.1. Condition Methodology

Liquefied natural gas system condition is determined primarily based on a preventive maintenance (PM) program comprised of rigorous inspections and renewals through component repair or replacement to improve system reliability.

The system is constantly monitored–control room operators provide the first line of defense by recognizing changing conditions and reacting in near real time. Online monitoring provides protection via control systems. Activities, such as corrective maintenance in response to component condition or operational performance, are captured in the work and asset management system. Component condition is determined using the experience and recommendations of both internal and external subject matter advisors (SMAs). As asset condition and performance degrade, risks are raised and assessed through the risk management process.

Aside from scheduled PM programs, age is also considered as a condition indicator for reliability and obsolescence, although it is generally insufficient on its own to use for replacement project decisions. As the asset ages, vendor support declines until the risk becomes intolerable. Obsolescence poses a risk as repairs become progressively more challenging to complete. As service providers reduce support for products reaching end-of-life, the duration of an equipment outage may become extended. Asset failure under these circumstances may be unrepairable, which could pose a significant operational challenge to fulfil facility requirements.

The LNG facility includes mechanical systems to support its primary function–compressors, vapourizers, a cold box (a series of heat exchangers), pumps, a cryogenic tank, generators, pipe, fittings, valves, regulators, boilers and air compressors (see **Figure 5.5-9**). The refrigeration system uses a mixed refrigerant consisting of methane, ethane, propane, butane and pentane. The condition of mechanical systems are assessed through routine PM inspections as prescribed by the manufacturer, through internally developed standards or through opportunistic inspections presented during construction activities.

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Instrumentation, controls and electrical systems support many other asset types and systems within the LNG facility and are primarily affected by obsolescence. As condition assessment for many of these assets is not practical, the methodology for establishing condition is to consider the expected equipment life cycle and proactively anticipate obsolescence.

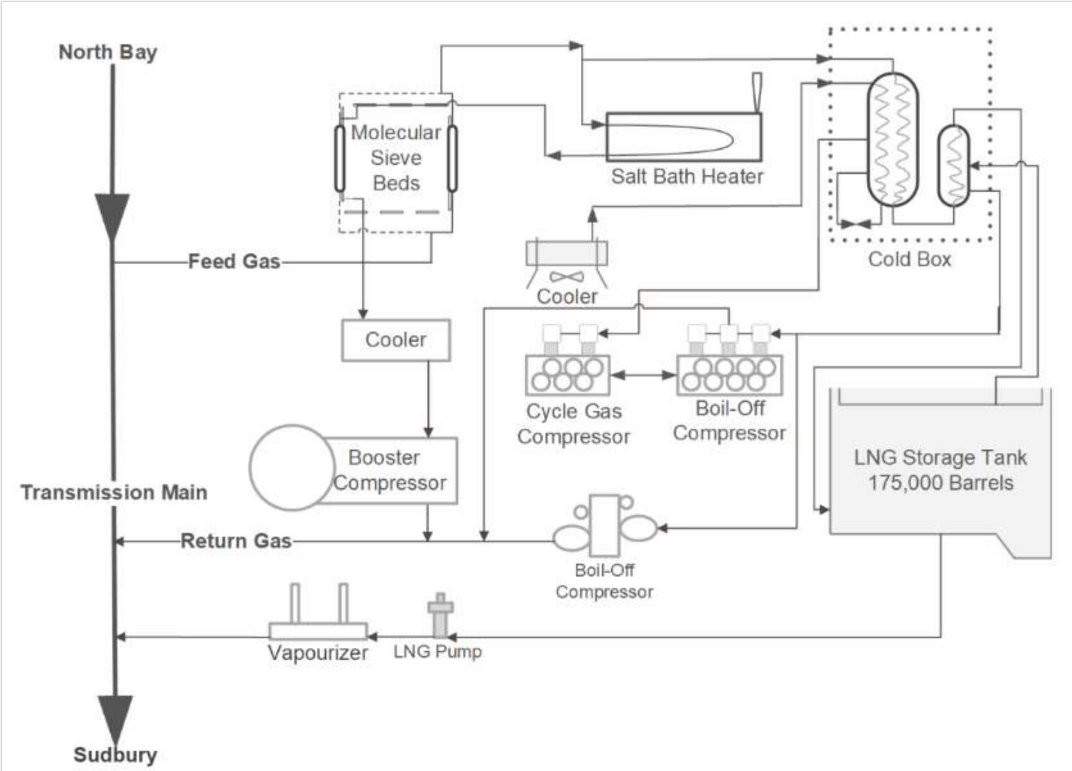

Figure 5.5-9: LNG Station

5.5.9.2. Condition Findings

EGI hired a third-party consultant to provide a condition assessment report for the Hagar LNG plant in 2017. The assessment focused on process performance limitations and equipment condition that could affect reliability and potentially lead to unplanned shutdowns. The assessment was supported through the annual risk review process with input from SMAs.

Assessment results indicated that the Hagar boil-off gas (BOG) compressor has far exceeded its design life as the unit has approximately 40 years of operational hours–it is original equipment in place since plant installation in 1968. A key LNG station component, the typical lifespan of a BOG compressor is 20 years, based on industry data and external SMA input.

Results also showed the cycle gas compressor has over 16 years of total operating hours (~140,000 hours) and is nearing end-of-life. The liquefaction system (composed of a cold box, cycle gas compressor, mixed refrigerant and auxiliary equipment) is also approaching end-of-life.

Operating life is only one measure of plant condition–other factors to consider include plant cycling frequency (On/Off) and plant age (regardless of operation). On/Off operation, particularly in unplanned shutdowns or quick start-ups, can result in thermal stress leading to material fatigue, cracking and pump cavitation. Time-dependent failure modes include corrosion, embrittlement and stress corrosion cracking.

The cold box was observed to have wall ice formations and minor foundation cracks–both are being monitored for progression. The condition assessment report also suggests insulation is degrading; frequent stops and starts will accelerate crack growth and should be minimized. The cold box has also undergone a considerable number of thermal cycles over its 50-year operating life–thermal cycling induces stress on piping and heat exchangers. A cold box failure will have a significant impact on plant availability and its replacement is considered a high priority as a considerable amount of time is required for design, procurement, construction and commissioning activities.

SMAs have confirmed the BOG and cycle gas compressors are no longer supported by the manufacturer and custom machining is required for parts other than typical wear items, rendering the equipment obsolete. A major concern is damage to

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the engine or compressor block due to a crankshaft, connecting rod or piston rod failure. The turnaround time for machined parts for the BOG compressor is likely to be less than a year but far longer for the cycle gas compressor, based on sheer size. Availability of replacement cast components for the cycle gas compressor is very limited. The control panel for the back-up generator has also been identified as obsolete and replacement parts are no longer available. Obsolescence occurs when equipment is no longer supported by the manufacturer and replacement parts cannot be fabricated and installed in time to meet the plant's operating requirements.

The areas around the LNG tank, near the LNG pipe supports and the LNG building suffer from water pooling, which can cause foundation settling. Differential settling between the tank and piping can cause stress in the piping and connections. Relative movement between the pipe, LNG pump and tank support foundations would result in internal tank nozzle loading and potential cracking.

5.5.9.3. Risk and Opportunity

The Hagar LNG plant provides security of supply to the Sudbury industrial and distribution markets. In addition to security of supply, the plant has also been placed in service on occasion over the years to manage system demand. The consequence of LNG system failure is dominated by gas cost impacts to customers. System risk associated with failure is heavily influenced by the time of year, weather severity and time to mitigate the failure.

Operational Risk: The reliability of the LNG system is integral to managing operational risk and customer impact. Unplanned failures, especially during peak periods, supply shortfalls and unplanned pressure drops or outages, can have a significant impact on the security of supply for the Sudbury area. The operational risks existing within the LNG facility are primarily related to obsolescence and the long lead time associated with a failure on critical assets within the liquefaction process (BOG compressor, cycle gas compressor and cold box).

Financial Risk: Financial risk is significantly mitigated by regular inspections, which then inform the necessary preventive maintenance work. A preventive maintenance program mitigates financial risk by reducing the chance of unexpected failures. Unplanned outages result in unexpected repair costs.

5.5.9.4. Strategy Outcomes

Detailed inspections at set frequencies, subsequent remedial activities and control room condition monitoring help identify suspect equipment condition, reducing the likelihood of failure and large-scale outages.

The replacement strategy for the LNG asset subclass is proactive replacement that targets equipment based on condition and obsolescence and is generally dependent on OEM support. This strategy aims to proactively replace or rebuild station components before end-of-life to reduce risk and maintain a safe and reliable LNG system.

This section outlines resolution of a number of discrete risks through replacement of individual components. EGI continues to broaden its understanding of the compatibility of new equipment with the existing balance of the plant. When replacing obsolete assets, EGI will continue to re-evaluate new technology to support a holistic plan for the modernization of the Hagar plant. The outcome of this analysis may result in an approach that favors broad plant renewal.

JVG Boil-off Gas (BOG) Compressor Replacement

This project involves replacement of the BOG compressor to mitigate the risk of a system failure due to a non-repairable, critical compressor part. The BOG compressor is one of the two compressors used to power the refrigerant process which cools the natural gas feedstock to -160 Celsius (at which point the natural gas turns into a liquid). Over its more than 50 years of operation, the 240-horsepower Ingersoll Rand BOG compressor has amassed 325,000 operational hours and deemed to be at the end of its design life. Although normal wear components are still available, core compressor replacement parts such as cylinders, crankshafts, pistons, etc., required to support a critical failure are no longer manufactured. In a critical failure, securing used parts (which are rare) or after-market custom machining services are the only options for repair. If custom machining services cannot repair the part, a custom-designed after-market casting option or complete replacement of the compressor will be required, rendering the LNG plant out of service for at least one operational season and unable to perform its regulated requirements.

KVGR Cycle Gas Compressor Replacement

This project involves replacement of the KVGR cycle gas compressor to mitigate the risk of a system failure due to a non-repairable, critical compressor part. The KVGR compressor is one of the two compressors used to power the refrigerant process (the other is the BOG compressor). Over its 50 years of operation, the 1500-horsepower Ingersoll Rand KVGR cycle gas compressor has amassed 140,000 operational hours and deemed to be at the end of its design life. This replacement is required for the same reasons as the BOG compressor.

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Cold Box Replacement

This project involves replacement of the cold box to address anticipated leaks that will impair the plant's ability to produce LNG. The cold box is a series of several heat exchangers used to cool natural gas, turning it into a liquid. Over its 50 years of operation, the cold box has amassed 140,000 operational hours. Significant failure modes include gas or refrigerant leaks out of the piping into the interior of the cold box shell and heat exchanger cross leaks that reduce refrigeration effectiveness. Both failure modes impair LNG production, leading to the plant missing its annual production requirements. Troubleshooting and repair of these failure modes is extremely difficult and time consuming, as cold box internal components are encased in very densely packed insulation and clad in an outer steel jacket. Considering the repair or replacement complexity, reactively responding to internal leakage will halt the liquefaction process, which lead to the non-fulfilment of EGI's regulated requirements for at least an operating season.

Site Drainage Improvements

This project includes the development of a drainage plan, engineering design, permitting and site remediation work to address water pooling near the LNG storage tank drainpipe, the LNG pump and the LNG building to prevent the foundation from sinking.

5.5.9.5. LNG Asset Class Capital Expenditure Summary

EGI has spent an average of $0.8M annually in the Union North rate zone for the Liquefied Natural Gas (LNG) asset class. The total average capital spend is forecasted to be $5M as summarized in **Table 5.5-8**. Storage and Transmission capital is further summarized as part of EGI's total 5-year capital plan in **Section 6.**

Table 5.5-8: Liquefied Natural Gas Capital Summary ($ Thousands) – Union Rate Zones

Asset Subclass/ Program Name	2021	2022	2023	2024	2025	Five-Year Forecast
Replacements	**-**	**-**	**16,030**	**-**	**-**	**16,030**
JVG Boil-off Gas (BOG) Compressor Replacement	-	-	8,015	-	-	8,015
KVGR Cycle Gas Compressor Replacement	-	-	8,015	-	-	8,015
Land/Structures Improvements	**-**	**243**	**-**	**189**	**354**	**786**
Site Drainage Improvements	-	-	-	189	354	542
Integrity	-	-	-	-	**8,327**	**8,327**
Cold Box Replacement	-	-	-	-	8,327	8,327
Improvements	**339**	**-**	**-**	**-**	**-**	**339**
Union Rate Zones Total	**339**	**243**	**16,030**	**189**	**8,681**	**25,483**

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5.6 Real Estate and Workplace Services

The Real Estate and Workplace Services (REWS) asset class includes properties (buildings and land) and furnishings. Properties are categorized into regional operations and administrative centres, operations depots, land, operations micro depots and head offices. The requirements for these properties are primarily based on function, headcount and organizational structure.

5.6.1 Real Estate and Workplace Services Objectives

The objectives of the Real Estate and Workplace Services asset class are listed in **Table 5.6-1**.

Table 5.6-1: Asset Class Objectives

Asset Class Objective	
Create and support safe, efficient and collaborative environments across EGI.	Sustain the integrity and adequacy of all facilities for safe and reliable use.
	Continuously evolve the understanding of condition and risk associated with real estate assets and use risk, cost and performance information to drive asset-related decisions.

The performance measures for the Real Estate and Workplace Services asset class are:

- Physical Assessment: Facility Condition Index (FCI)
- Functional Assessment: Adequacy Index (AI)
- Cost per square foot (lease and building operating expenditures)
- Utilization rate

To achieve the Real Estate and Workplace Services asset class objectives listed in **Table 5.6-1**, asset investment decisions are governed by the life cycle management strategies outlined in **Table 4.1-1**.

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5.6.2 Real Estate and Workplace Services Hierarchy

The asset class hierarchy is summarized in **Figure 5.6-1**.

Figure 5.6-1: Real Estate and Workplace Services Hierarchy

5.6.3 Real Estate and Workplace Services Inventory

The inventory for Real Estate and Workplace Services assets can be found in **Table 5.6-2**.

Table 5.6-2: Real Estate and Workplace Services Asset Class Inventory

Asset Subclass	EGD Rate Zone	Union Rate Zones
Properties (Buildings/Land)	18	74
Head Offices	1	0
Regional Operations and Administrative Centres	3	8
Operations Depots	12	42
Operations Micro Depots	0	18
Land	2	6
Workspace Furniture	~2,400	~3,200

The total building square footage is 774,665 and 1,245,291 for the EGD and the Union rate zones respectively.

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5.6.4 Real Estate and Workplace Services Condition and Strategy Overview

Asset Subclass/Program	Ave. Age (Year)	Ownership	Condition	Risk / Opportunity	Maintenance Strategy	Replacement / Renewal Strategy
Properties (Buildings / Land)	N/A	Owned and leased	Facility assessments were conducted on EGI properties, based on a defined set of standards representing industry best practices relating to exterior site works, architectural elements, interiors, furniture and amenities. Using the Functional Obsolescence or Adequacy Index (AI), a condition index tool used to illustrate the functional condition of the asset. The Facility Condition Index (FCI), a generally-accepted industry benchmarking tool was also used. All EGI properties were inspected for the purpose of calculating an FCI and creating a long-term capital plan. See **Table 5.6-3** for the condition findings for each property.	**Employee and Contractor Safety Risk**: Facilities with operational deficiencies pose a safety risk to employees and hinder execution of tasks. Some facilities have inadequate operations yard and administrative parking. The mix of industrial and employee vehicles is a potential contributor to motor vehicle incidents. **Financial Risk**: EGI faces financial risk if properties are not maintained, hindering operations and administrative functions. Some facilities uses more energy than a comparable renovated facility (utilizing current Ontario Building Code (OBC) and energy standards). Inadequate site configuration and lack of office and support areas hinder operations and administrative functions. Older buildings have high greenhouse gas emissions and uses more energy than a comparable new construction.	A preventive maintenance strategy is in place to ensure asset performance and reduce the risk of failure or degradation of performance in supporting of occupants.	The strategies for the Properties asset subclass were developed to align with business requirements and the OBC as well as to correct deficiencies on site: • Renovating existing facilities • Building new facilities • Disposing of current site and relocating to a new site • Continuing maintenance of the current site Choosing the appropriate strategy is based on a combination of physical/functional assessments and support of the business strategy.
Workplace Furnishings	N/A	Owned	Workspaces at each site consist of workstations and office furniture. These furnishings are either considered current (meeting EGI standards) or legacy (not meeting current standard). Current EGI furniture standards provide: • Ergonomic support • Daylight and views for building occupants through the use of mid-height panel systems • Task seating to address a range of body types • Consistent workstation configuration • Lower operating costs by contributing to fixed environments that allow a broad range of administrative requirements without change.	**Employee and Contractor Safety Risk**: Legacy furnishings do not meet current ergonomics standards; therefore, employees are more likely to suffer from repetitive strain injuries and other ailments stemming from decreased access to light. **Financial Risk**: Legacy furnishings approaching 30 years old result in productivity reductions and increased maintenance costs.	N/A	The strategy for the Workplace Furnishings asset subclass is to replace office and meeting room furnishings as required. Remaining legacy office, meeting room and ancillary furnishings are replaced with current standard systems as building life cycle renewal is executed. Ergonomic modifications and tools are issued as recommended to prevent repetitive strain injuries and accommodate return-to-work employees. .
Building Systems Program	N/A	N/A	A third-party engineering consulting company was employed by EGI to analyze factors such as age of equipment, maintenance records, repair cost, building standards and compliance issues to determine overall risks and the replacement timing of heating, ventilation, air conditioning (HVAC) equipment, plumbing, electrical systems, building envelope, facilities equipment and exterior site improvements.	**Financial Risk**: If building systems are not properly maintained, there is financial risk to EGI as the failure of these systems increases substantially, which can potentially lead to loss of use and decreased staff productivity.	N/A	The renewal/replacement strategy for building systems assets is to maximize equipment useful life and replace building systems before failure, including the replacement of the building envelope, HVAC and electrical systems to current environmental standards, ensuring interior comfort and overall security.
GHG Energy Reduction Program	N/A	N/A	EGI has started a third-party study on energy efficiency and emissions for its office buildings. The study identifies operational improvements needed to ensure building systems are operated efficiently to reduce natural gas use.	Existing facilities use more energy than a comparable new or renovated facility (using current OBC and energy standards). Existing facilities emit more greenhouse gases that can potentially affect ratepayers. **Energy Efficiency Opportunity**: Reduction in operating costs or GHG emissions	N/A	Existing building commissioning at locations not planned for improvements in the five-year plan will be reviewed or recommissioned through a third party to identify a mix of measures with a range of implementation costs and energy/greenhouse gas savings. Once completed, measures, findings and an action plan to measure energy conservation implementation will be developed, as well as verification and ongoing commissioning, which will include operational and capital improvements. Lessons learned will be implemented on future initiatives.
Micro-Operations Depot Revitalization Program	N/A	Owned and leased	There are 18 micro-operations depots located in the Northern region that are on average over 50 years old, consisting of 17 owned and one leased property. The sites are in aging physical condition and do not meet required functionality.	**Financial Risk**: Risks include the financial impact of low utilization or functionally and physically deficient assets. **Employee and Contractor Safety Risk**: Current physical conditions pose a hazard to employee safety. Legacy buildings with obsolete systems have high GHG emissions and use more energy than a comparable new construction.	N/A	The strategy is to renovate or replace 14 identified target micro-operations depot sites. Renovations or replacement will include the building envelope, HVAC and electrical systems. Compliance to environmental standards, building codes, accessibility and overall security are major considerations to ensure safe and reliable operation.

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5.6.5 Properties

5.6.5.1. Condition Methodology

For the Properties (buildings/land) asset subclasses, a Facility Assessment is used to:

- Assess the physical condition of each facility
- Assess the operational functionality of each facility
- Identify potential gaps in service area coverage
- Create a long-term real estate portfolio strategy
- Create quality indoor environments with access to natural light and views which result in increased productivity, decreased absenteeism and improved morale

The Facility Assessment is based on a defined set of standards representing industry best practices relating to exterior site works, architectural elements, interiors, furniture and amenities.

The Functional Obsolescence or Adequacy Index (AI) is a condition index tool used to illustrate the functional condition of the asset expressed in a percentage ratio of required functional upgrade costs divided by the replacement value of the asset to meet functional needs. Based on EGI's standards, scores between 0% and 49% are considered good and scores of 50% and above are considered poor/critical. The AI is calculated as follows:

Adequacy Index Calculation

$$\mathbf{AI} = \frac{\textbf{Functional Upgrade Costs}}{\textbf{Cost to Replace the Building with its Functional Equivalent}}$$

An asset's physical condition is assessed based on the Facility Condition Index (FCI). The FCI is a generally-accepted industry benchmarking tool. It is a scoring mechanism comparing the relative physical condition of the existing components of a group of facilities. All EGI properties have been inspected for the purpose of calculating an FCI and creating a long-term capital plan. Based on EGI's standards, scores between 0% and 5% are considered good, 5% to 10% fair, 10% to 30% poor and greater than 30% critical. The FCI is calculated as follows:

Facility Condition Index Calculation

$$\mathbf{FCI} = \frac{\textbf{Cost to Remediate Immediate or Short– term Maintenance Deficiencies}}{\textbf{Current Replacement Value of Facility}}$$

Site functionality and utilization are based on critical functional criteria (yard size, access, sufficient office area, tracked utilization, etc.) and are scored as Good, Challenged, or Obsolete. The typical yard size is 2.5 acres (the appropriateness is dependent on EGI site-specific requirements).

Properties are assessed based on multiple parameters such as; site and building functional obsolescence, physical obsolescence, Ontario Building Code (OBC) compliance and renewal/replacement strategy costs. Each property is assigned a priority rank from highest to lowest. To attain this rank, building functional obsolescence (AI), physical obsolescence index (FCI), site functional obsolescence index and the recommended strategy for correcting the deficiencies were considered. Higher priority is given to the facilities posing larger and more immediate financial and/or safety risk to the organization.

Compliance to current OBC requirements is factored, depending on the Part, Group and Division each property falls under. These include (but are not limited to) barrier-free path of travel and barrier-free and universal washroom facilities. Furthermore, compliance with fire code regulations on load-bearing structures, fire resistance ratings, sprinkler systems and combustible/non-combustible construction are also considered. It is important to note that major renovations to a structure may require that area to be brought up to current OBC compliance standards, potentially requiring a substantial investment.

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5.6.5.2. Condition Findings

Table 5.6-3 shows the facility assessment results for all EGI properties and the summary strategy for each property. Based on EGI's standards, FCI scores between 0% and 5% are considered good, 5% to 10% fair, 10% to 30% poor and greater than 30% critical. AI scores between 0% and 49% are considered good and scores of 50% and above are considered poor/critical. Site functionality and utilization are based on critical functional criteria (yard size, access, sufficient office area, tracked utilization, etc.) and are scored as Good, Challenged, or Obsolete.

Table 5.6-3: EGI Facility Assessment Results

Property Name	Age (Years)	Physical Obsolescence (FCI)	Functional Obsolescence: Building (AI)	Functional Obsolescence: Site	Summary Strategy
50 Keil Drive	56	12.91%	44.64%	Obsolete	Renovation
555 Riverview Operations Centre	48	10.03%	24%	Good	Renovation
Ancaster Operations Centre	28	8.88%	63%	Obsolete	Expansion and Renovation
Bloomfield Administration Centre	28	0.47%	0.18%	Good	Maintenance
Brantford Regional Operations Centre	25	2.77%	17%	Obsolete	Renovation
Burlington Operations Centre	12	1.77%	11%	Obsolete	Renovation
Cambridge Operations Centre	58	11.76%	16%	Obsolete	Disposition
Dawn Hub Operations Centre	50	16.95%	28%	Obsolete	New build on existing site
Dryden Operations Centre	41	11.33%	87%	Obsolete	New build on new site
Guelph Operations Centre	63	14.97%	46%	Obsolete	Disposition
Kingston Operations Centre	11	0.32%	15%	Good	Maintenance
Hamilton Operations Centre (Park Street)	60	26.86%	100%	Obsolete	Disposition
Hamilton Operations Centre (Pritchard Road)	13	7.91%	21%	Obsolete	Renovation
Leamington Operations Centre	59	9.85%	65%	Good	Renovation
London Operations Centre	52	6.48%	14%	Good	Disposition

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Property Name	Age (Years)	Physical Obsolescence (FCI)	Functional Obsolescence: Building (AI)	Functional Obsolescence: Site	Summary Strategy
Milton Operations Centre	26	14.09%	63%	Obsolete	Disposition
North Bay Operations Centre	56	16.87%	8%	Good	New build on new site
Orillia Operations Centre	46	18.07%	15%	Obsolete	Renovation
Owen Sound Operations Centre	14	4.52%	32%	Obsolete	Expansion and Renovation
Sault Ste. Marie Operations Centre	42	13.90%	24%	Good	Renovation
Simcoe Operations Centre	64	8.42%	100%	Good	Demolish and New Build
St. Thomas Operations Centre	41	12.59%	22%	Obsolete	Disposition
Stratford Operations Centre	53	11.96%	22%	Good	Expand on current land
Sudbury Operations Centre	36	8.49%	13%	Obsolete	Renovation
Thunder Bay Regional Operations Centre	24	2.57%	41%	Obsolete	Renovation
Timmins Operations Centre	61	2.88%	25%	Good	Renovation
Woodstock Operations Centre	38	13.87%	26%	Obsolete	Renovation
Atikokan Micro-Operations Centre	53	11.37%	61%	Good	Revitalization Program
Black River Micro-Operations Centre	52	36.09%	46%	Good	Revitalization Program
Bracebridge Micro-Operations Centre	53	19.41%	32%	Good	Revitalization Program
Cochrane Micro-Operations Centre	54	15.28%	50%	Good	Revitalization Program
Ear Falls Micro-Operations Centre	6	6.82%	56%	Good	Maintenance
Elliot Lake Micro-Operations Centre	41	29.09%	9%	Good	Revitalization Program
Engelhart Micro-Operations Centre	Unknown	25.42%	83%	Good	Revitalization Program
Geraldton Micro-Operations Centre	56	12.09%	68%	Good	Revitalization Program

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Property Name	Age (Years)	Physical Obsolescence (FCI)	Functional Obsolescence: Building (AI)	Functional Obsolescence: Site	Summary Strategy
Haileybury Micro-Operations Centre	55	22.60%	18%	Good	Revitalization Program
Hearst Micro-Operations Centre	47	6.76%	79%	Good	Revitalization Program
Huntsville Micro-Operations Centre	51	24.34%	52%	Good	Revitalization Program
Huron Park Micro-Operations Centre	80	42.40%	22%	Good	Disposition
Iroquois Falls Micro-Operations Centre	54	28.84%	16%	Good	Revitalization Program
Kapuskasing Micro-Operations Centre	30	7.11%	0%	Good	Maintenance
Kirkland Lake Micro-Operations Centre	56	11.38%	69%	Good	Revitalization Program
Nipigon Micro-Operations Centre	57	10.27%	57%	Good	Revitalization Program
Palmerston Micro-Operations Centre	Unknown	9.56%	88.7%	Good	Revitalization Program
Parry Sound Micro-Operations Centre	7	3.75%	19%	Good	Maintenance
Arnprior Operations Centre	50	3.82%	58%	Obsolete	Renovation
Barrie Operations Centre	15	1.61%	58%	Obsolete	Disposition
Brampton Operations Centre	22	11.02%	49%	Obsolete	Renovation
Brockville Operations Centre	50	7.53%	84%	Obsolete	New build and land
Kelfield Operations Centre	60	10.47%	71%	Obsolete	New build and land
Kennedy Road Operations Centre	60	6.51%	95%	Obsolete	New build and land
Oshawa Operations Centre	31	14.92%	30%	Obsolete	Renovation
Ottawa Regional Operations and Admin. Centre	60	4.65%	43%	Obsolete	Consolidation
Peterborough Operations Centre	39	10.38%	32%	Obsolete	Disposition
SMOC Operations Centre	25	2.04%	24%	Obsolete	Disposition

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Property Name	Age (Years)	Physical Obsolescence (FCI)	Functional Obsolescence: Building (AI)	Functional Obsolescence: Site	Summary Strategy
Station B Operations Centre	52	12.28%	49%	Obsolete	New build
Tecumseh (Gas Storage)	4	0.81%	0%	Good	Maintenance
Tecumseh (Engineering)	11	0.28%	0%	Good	Maintenance
Thorold Regional Operations and Admin. Centre	28	3.09%	59%	Obsolete	Renovation
TOC Regional Operations and Admin. Centre	9	0.08%	5%	Good	MEC and Telemetry Expansion
VPC Head Office	52	5.59%	11%	Good	Renovation, new build

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5.6.5.3. Risk and Opportunity

Examples of deficiencies observed at EGI sites were as follows:

- Inadequate building or yard size leads to unfulfilled operational requirements.
- Non-conformance to current OBC life safety, barrier-free and universal design standards
- Site area constraints hinder vehicular circulation and increases the probability of motor vehicle incidents.
- Configuration of site functions and circulation is inefficient.

These deficiencies pose the following risks:

Employee and Contractor Safety Risk: Facilities with operational deficiencies pose a safety risk to employees and hinder execution of tasks. Some facilities have inadequate operations yard and administrative parking. The mix of industrial and employee vehicles is a potential contributor to motor vehicle incidents. Best practices dictate keeping industrial vehicles away from administration parking areas.

Financial Risk: EGI faces financial risk if properties are not maintained, hindering operations and administrative functions. Some facilities use more energy than a comparable renovated facility (utilizing current OBC and energy standards). Inadequate site configuration and lack of office and support areas hinder operations and administrative functions. Older buildings have high greenhouse gas emissions and use more energy than a comparable new construction.

5.6.5.4. Strategy Outcomes

The strategies for the Properties asset subclass were developed to align with business requirements and the OBC as well as correct deficiencies on site:

- Renovating existing facilities
- Building new facilities
- Disposing of current site and relocating to a new site
- Continuing maintenance of the current site

Choosing the appropriate strategy is based on a combination of business requirements and physical/functional assessments described in **Section 5.6.5.1** and support of the business strategy. See **Table 5.6-3** for the summary strategy for each EGI property. This approach to long term planning of EGI properties aligns with the feedback received from customers in the 2020 Customer Engagement Survey. A vast majority of customers prefer that investments in renovating older buildings and building new ones be spread evenly over a longer period of 10 years as opposed to delaying these investments until they can no longer be avoided and funded more quickly, which could cost more in the long run.

Major investments for this asset class were identified through a facility assessment of the properties' physical condition and operational function and gaps in service area coverage, to allow for a standardized look and feel to all Enbridge facilities. Major projects include four new buildings and the relocation and consolidation of the Ottawa facilities for better operational coverage. Improvements at the 50 Keil Drive administrative facility are intended to extend the useful life of the property and accommodate over 800 employees. The investment will correct physical and functional deficiencies by renovating and renewing the existing building, using less energy and emitting less greenhouse gases.

Building Systems Program

A third-party engineering consultant analyzed factors such as age of equipment, maintenance records, repair cost, building standards and compliance issues to determine overall risks and timing of replacement for HVAC equipment, plumbing, electrical equipment and exterior site improvement.

The property assessment report identifies equipment at end-of-life and recommends a replacement plan over a 25-year span. The report focused on the design, installation, operation and monitoring of building systems required for a safe, comfortable and environmentally friendly environment for employees.

Unplanned failures occur occasionally which require immediate action. A review of each cost determines the decision to repair or replace the defective equipment. The service life of new assets is 15 to 20 years.

If building systems are not properly maintained, there is a financial risk to EGI as failure of these systems increase substantially year over year, which can potentially lead to loss of productivity.

The strategy for building systems assets is to maximize the equipment's useful life and replace systems before failure can cause business interruptions.

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The replacement of equipment is targeted but not solely specific to the building envelope, HVAC and electrical systems. Compliance to environmental standards, interior comfort and overall security are major considerations to ensure safe and reliable operations.

The annual program for these initiatives is determined based on historical spend as well as building assessments and condition analysis.

GHG and Energy Reductions Program

Enbridge has begun work on energy efficiency and emissions from office buildings. These improvements ensure current building systems are operated in an efficient manner that reduces carbon fuel use. The strategy on energy efficiency and emissions from office buildings identifies natural gas air-sourced heat pumps and other opportunities as a potential abatement opportunity at EGI's office facilities.

Some existing EGI facilities use more energy than a comparable new or renovated facility (utilizing current OBC and energy standards), increasing operating costs. This program will offer EGI the opportunity to reduce these costs by implementing energy efficiency measures in its office buildings, reducing GHG emissions.

Where work is not already a part of the five-year plan, improvements will still be reviewed to see if they can be accommodated, leading to further reduction in GHG and energy usage. The process will identify a mix of measures with a range of implementation costs and energy/greenhouse gas savings. On completion, measures, findings and an action plan to measure energy conservation implementation will be developed, as well as verification and ongoing commissioning, which will include operational and capital improvements. Lessons learned from each activity will be implemented on future initiatives. This is a recurring yearly program for five years, determined based on building assessments and condition analysis.

Micro-Operations Depot Revitalization Program

This program covers the renovation or replacement of 14 micro-operations depots located in the Northern region that are on average over 50 years old, consisting of 17 owned and one leased property. The sites are in aging physical condition and do not meet required functionality.

Risks include the financial impact of low utilization or functionally and physically deficient assets. Current physical conditions pose a hazard to employee and contractor safety. Legacy buildings with obsolete systems have high GHG emissions and use more energy than a comparable new construction.

The strategy is to renovate or replace the sixteen micro-operations depots. Renovations or replacement will include the building envelope, HVAC and electrical systems. Compliance to environmental standards, building codes, accessibility and overall security are major considerations to ensure safe and reliable operations.

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5.6.6 Workplace Furnishings

5.6.6.1. Condition Methodology

Workspaces at each site consist of workstations and office furniture. These furnishings are either considered current (meeting EGI standards) or legacy (not meeting current standard). Current EGI furniture standards provide:

- Ergonomic support
- Day lighting and views for building occupants through use of mid-height workspace systems and perimeter placement
- Task seating required to address a range of body types
- Consistent workstation configuration, contributing to lower operating costs by creating fixed environments and allowing a broad range of administrative requirements without change
- Designs using materials and features reducing the “cubicle feel”
- Designs supporting power and network wiring

Legacy furniture (20+ years old) does not meet EGI’s current condition standards. Legacy furniture is comprised of furniture systems purchased in the mid-1980s when the concept of systems furniture was first implemented. Office environment and related standards have evolved over the past 30 years. The systems still in use are high-paneled, impeding daylight into the office environments. Legacy furniture has surpassed its 10-year warranty period (the anticipated use length) and is approaching 30 years in age.

In addition, ergonomic requirements have changed to support EGI’s goal of zero injuries in the office. The height of the existing fixed workstation at 29” is a contributing factor of repetitive strain injury. Current standard workstations allow for adjustable height work surfaces, allowing employees to adjust their work surface to the appropriate height or to stand if desired.

Ancillary furnishings refer to all support furnishings, including (but not limited to) guest seating, informal and collaborative areas, conference room and common space furniture, filing cabinets and bookcases. The condition of ancillary furnishings is based on an assessment of age, physical condition and utilization and is also evaluated as either meeting or not meeting EGI standards.

5.6.6.2. Condition Findings

The facility assessment results for all EGI properties included an assessment of workplace furnishings. Results indicate that except for the Victoria Park Centre (VPC) and Technology and Operations Centre (TOC) properties, all of EGI’s workplace furnishings are rated as legacy based on EGI standards. 30% of furnishings are current; 70% are legacy.

5.6.6.3. Risk and Opportunity

Without adequate furniture and ergonomics in place, there is financial risk as productivity can potentially suffer due to inefficient space allocation and unnecessary workstation re-configuration costs. Improper ergonomics support can pose a safety risk as lack of task seating that addresses a range of body types can potentially cause repetitive strain injuries.

Financial Risk: Furnishings approaching 30 years old reduce productivity and increase maintenance costs.

Employee and Contractor Safety Risk: Legacy furnishings do not meet current ergonomics standards; therefore, employees are more likely to suffer from repetitive strain injuries and other ailments stemming from the inability to adjust workstation configurations.

5.6.6.4. Strategy Outcomes

The strategy for furniture and ergonomics assets is to replace office and meeting room furnishings as required due to failure. Ergonomic modifications and tools are issued as recommended to prevent repetitive strain injuries and accommodate return-to-work employees. The annual program is based on historical spend.

Remaining legacy office, meeting room and ancillary furnishings are replaced with current standard systems as building life cycle renewal is executed.

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5.6.7 Real Estate and Workplace Services Capital Expenditure Summary

EGI has spent an average of $19M and $12M annually in the EGD and Union rate zones respectively for the Real Estate and Workplace Services (REWS) asset class. The total average capital spend is forecasted to be $33M (EGD RZ) and $35M (Union RZ) as summarized in **Table 5.6-4** and **Table 5.6-5**. REWS capital is further summarized as part of EGI's total five-year capital plan in **Section 6.**

Table 5.6-4: REWS Capital Summary ($ Thousands) – EGD Rate Zone

Asset Subclass/Program	2021	2022	2023	2024	2025	Five-year Forecast
Furniture/Structures and Improvements	**58,556**	**45,882**	**21,553**	**16,339**	**24,810**	**167,140**
Kennedy Road Expansion	1,221	14,597	2,564	-	-	18,832
Station B New Building	18,921	-	-	-	-	18,921
SMOC/Coventry Facility Consolidation	9,766	14,597	13,897	-	-	38,241
Kelfield Operations Centre	6,104	5,717	1,410	-	-	13,231
VPC Core and Shell	-	-	-	12,447	13,219	25,666
Building Systems Program	2,313	2,345	2,513	2,483	2,683	12,338
Targeted GHG and Energy Reductions	427	426	449	436	463	2,200
EGD Rate Zone Total	**59,556**	**44,882**	**21,553**	**16,339**	**24,810**	**167,140**

Table 5.6-5: REWS Capital Summary ($ Thousands) – Union Rate Zones

Asset Subclass/Program	2021	2022	2023	2024	2025	Five-year Forecast
Furniture/Structures and Improvements	**44,928**	**35,736**	**26,280**	**21,498**	**48,570**	**177,011**
Thunder Bay Regional Operations Centre	-	-	-	754	12,806	13,561
New Site No. 4	12,228	12,170	11,299	-	-	35,697
Targeted GHG and Energy Reductions	428	426	449	440	467	2,210
Micro-Operations Depot Revitalization	2,446	2,434	2,568	2,514	2,668	12,630
Union Rate Zones Total	**44,928**	**35,736**	**26,280**	**21,498**	**48,570**	**177,011**

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5.7 Fleet and Equipment

The Fleet and Equipment asset class provides EGI with the necessary vehicles, equipment and tools to safely and efficiently run regulated business operations. EGI sustains the integrity of the fleet through a strong maintenance program and uses risk, cost and performance information to drive asset-related decisions.

The Fleet and Equipment asset class consists of three asset subclasses: Fleet, Heavy Equipment and Tools. Fleet includes light duty vehicles (LDVs), medium duty vehicles (MDVs) and heavy duty vehicles (HDVs). LDVs include cars, vans and pickup trucks. MDVs include vehicles which range from mechanic repair trucks to utility service trucks. Heavy duty vehicles are comprised of large vehicles with a Gross Vehicular Weight (GVW) between 26,001 - 150,000 pounds. Heavy equipment assets consists of backhoes, trailers, compressors, forklifts, welders and boring equipment. The Tools asset subclass consists of all tools that support EGI's business operations, ranging from gas surveyors and concrete saws, to fusion machines, pipe squeeze-off tools and stop/tap tooling equipment.

5.7.1 Fleet and Equipment Objectives

Table 5.7-1 describes the asset class objectives for Fleet and Equipment.

Table 5.7-1: Fleet and Equipment Asset Class Objectives

Asset Class Objectives	
Supportability	Provide the business with the necessary vehicles, equipment and tools to safely and efficiently run regulated business operations.
Integrity and Reliability	Sustain the safety and reliability of all vehicles, equipment and tools.
	Use risk, cost and performance information to drive asset-related decisions.

The performance measures for the Fleet and Equipment asset class are:

- 100% completion of end-user requirements
- Preventive maintenance activities completed on schedule
- Fleet management system reporting and qualitative reviews completed

To achieve Fleet and Equipment asset class objectives listed in **Table 5.7-1**, asset investment decisions are governed by the life cycle management strategies outlined in **Table 4.1-1**. For this asset class, specific life cycle activities include:

- Convert LDVs where applicable to operate on natural gas, reducing overall GHG emissions.
- Install Auxiliary Power Units (APU) on MDVs (An APU is an anti-idling device that reduces overall GHG emissions and prevents premature engine wear and tear).
- Optimize natural gas as a fuel source for LDVs to reduce overall GHG emissions.
- Install telematics/GPS technology to optimize asset utilization.
- Use telematics/GPS technology to create a proactive approach to vehicle maintenance and reduce downtime.

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5.7.2 Fleet and Equipment Hierarchy

The asset subclass breakdown for the Fleet and Equipment asset class is illustrated in **Figure 5.7-1.**

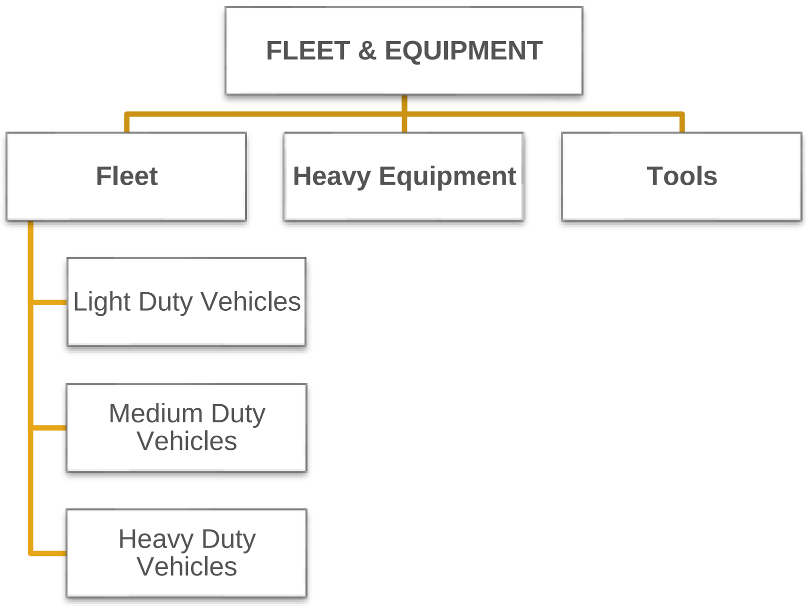

Figure 5.7-1: Fleet and Equipment Asset Class Hierarchy

5.7.3 Fleet and Equipment Inventory

The Fleet and Equipment asset class inventory is shown in **Table 5.7-2**.

Table 5.7-2: Fleet and Equipment Inventory

Asset Subclass	EGD Rate Zone	Union Rate Zones
Fleet	1069	826
Light Duty Vehicles	880	550
Medium Duty Vehicles	6	233
Heavy Duty Vehicles	183	43
Heavy Equipment	689	510
Tools	~5000	~6000

5.7.4 Fleet and Equipment Condition and Strategy Overview

Asset Subclass		Avg. Age (Year)	Condition	Risk / Opportunity	Maintenance Strategy	Replacement / Renewal Strategy
FLEET	**Light-Duty Vehicles**	5.3 (EGD RZ) 4.5 (Union RZ)	Analysis indicates that average maintenance costs exceed the market value of a light-duty vehicle at an approximate age of five to seven years or 160,000 kilometres, depending on the vehicle's weight class.	**Financial Risk**: Aging fleet vehicles primarily pose a financial risk to EGI if they are not maintained or replaced as needed. Maintenance costs increase beyond the vehicle value and productivity may be impacted due to increased downtime as a result of more frequent unplanned maintenance activities.	Vehicle maintenance every 8,000 kilometres (approximately every three months)	**Light Duty Vehicle (LDV) Replacement Strategy**: this proactive program replaces vehicles based weight class, mileage and assessed condition. The replacement schedule is as follows: • Class 1 Vehicles – 60 months • Class 2 Vehicles – 72 months • Class 3 Vehicles – 84 months The average replacement age for LDVs is 6 years and the optimal average age for the asset pool (the midpoint of the average replacement) is calculated at 3 years.
FLEET	**Medium-Duty Vehicles**	9.3 (EGD RZ) 5.2 (Union RZ)	Analysis indicates that average maintenance costs exceed the market value of a medium-duty vehicle at approximately seven to 12 years old or 175,000 kilometres, depending on the vehicle's weight class.		Vehicle maintenance every 10,000 kilometres or 500 engine hours (approximately every four months)	**Medium Duty Vehicle (MDV) Replacement Strategy**: this proactive program replaces vehicles based on weight class, mileage and assessed condition. The replacement schedule is as follows: • Class 4 Vehicles – 84 months • Class 5 Vehicles – 120 months • Class 6 Vehicles – 144 months The average replacement age for MDVs is 9.7 years and the optimal average age for the asset pool is calculated at 4.85 years.
FLEET	**Heavy-Duty Vehicles**	7.6 (EGD RZ) 8.1 (Union RZ)	Analysis indicates that average maintenance costs exceed the market value of a heavy-duty vehicle at 12 years old or 350,000 kilometres, depending on the vehicle's weight class.		Vehicle maintenance every 10,000 kilometres or 500 engine hours (approximately every four months)	**Heavy Duty Vehicle (HDV) Replacement Strategy**: This proactive program replaces vehicles based on weight class, mileage and assessed condition. The replacement schedule is as follows: • Class 7 Vehicles – 144 months • Class 8 Vehicles – 144 months The average replacement age for HDVs is 12 years and the optimal average age for the asset pool is calculated at 6 years.
Heavy Equipment		10.7 (EGD RZ) 7.9 (Union RZ)	Analysis indicates that average maintenance costs exceed the market value of heavy equipment at approximately 12 years old.		Equipment maintenance is conducted on a scheduled basis, ranging from three to 12 months, depending on the type of equipment.	**Heavy Equipment Replacement Program**: this proactive program is based on average historical spending and is driven by: • Proactively replacing assets based on a detailed physical condition assessment • Acquiring net new equipment based on business needs.
Tools		N/A	The general condition and functionality of tools are assessed by the operator prior to use and during scheduled inspections and calibrations.	Aging, broken, or inadequate tools pose the following risks: **Financial Risk**: Increased maintenance costs and lower productivity **Employee and Contractor Safety Risk and Public Health and Safety Risk**: Increased employee, contractor and customer safety and health risks if tools are not in good condition. **Operational Risk**: Service and/or emergency response reliability	N/A	**Tools Replacement Program**: this reactive program is in place to address tools that are: • Showing signs of wear and tear, broken and/or unrepairable • Stolen or lost • Declared obsolete by the manufacturer or supplier • No longer approved for use due to updated Engineering standards and practices • Needed and requested by EGI operating departments to perform their business functions

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5.7.5 Fleet

5.7.5.1. Condition Methodology

As part of integration activities, fleet data will be migrated to an enterprise-wide fleet management service provider in 2020, to use fleet management software (Element) that stores asset records and analyzes vehicle condition over their life cycle. This includes all maintenance costs, fuel consumption, mileage, age and hours of use.

Fleet management software provides data to analyze a vehicle's cumulative maintenance cost against the asset class's average cost and the asset condition. An asset is assessed and considered for replacement once the average maintenance cost surpasses market value, unless there are conditions observed that justify shortening or prolonging asset life. If a vehicle exhibits higher maintenance costs than average, the vehicle is considered for earlier replacement. On the other hand, if a vehicle exhibits lower maintenance costs and assessed to be in good condition, it is considered for later replacement. This approach is guided by risk analysis, operating expense and asset performance to sustain asset integrity. A steady pace of replacements spread out evenly over a longer period is consistent with customer engagement feedback.

Retaining vehicles and heavy equipment too long increases operating and maintenance costs. Furthermore, retiring these assets too early results in the partial loss of their useful life, impacting capital replacement requirements. For vehicles, the population's average point at which maintenance costs exceed the market value of the vehicle is used as a guide, as it helps identify vehicles approaching end-of-life. These vehicles require a detailed condition assessment to determine their fitness for service, which consists of appraising vehicle attributes such as engine, transmission, body and interior condition. For heavy equipment, the standard used to determine the optimal replacement point is when maintenance costs begin to exceed the market value of the asset.

In addition to reports, detailed condition assessments are conducted on vehicles and heavy equipment assets every three to six months. This assessment includes a physical and visual evaluation of the asset's physical and functional condition, a comparison of hours of service and an assessment of the maintenance history of the asset relative to its class. If the asset is assessed to be in good working condition, it is kept in service and refurbished to extend its useful life. If the asset is assessed to be in poor condition and not fit for continued service, it is replaced.

To understand how company vehicles are being used, fleet vehicles are equipped with Global Positioning System (GPS)/Telematics tracking devices, managed by fleet management software (Geotab). The Geotab system also provides real-time vehicle diagnostics, giving EGI the ability to be proactive with fleet vehicle assessments and repairs.

5.7.5.2. Condition Findings

Figure 5.7-2 shows the average age for fleet assets across EGI.

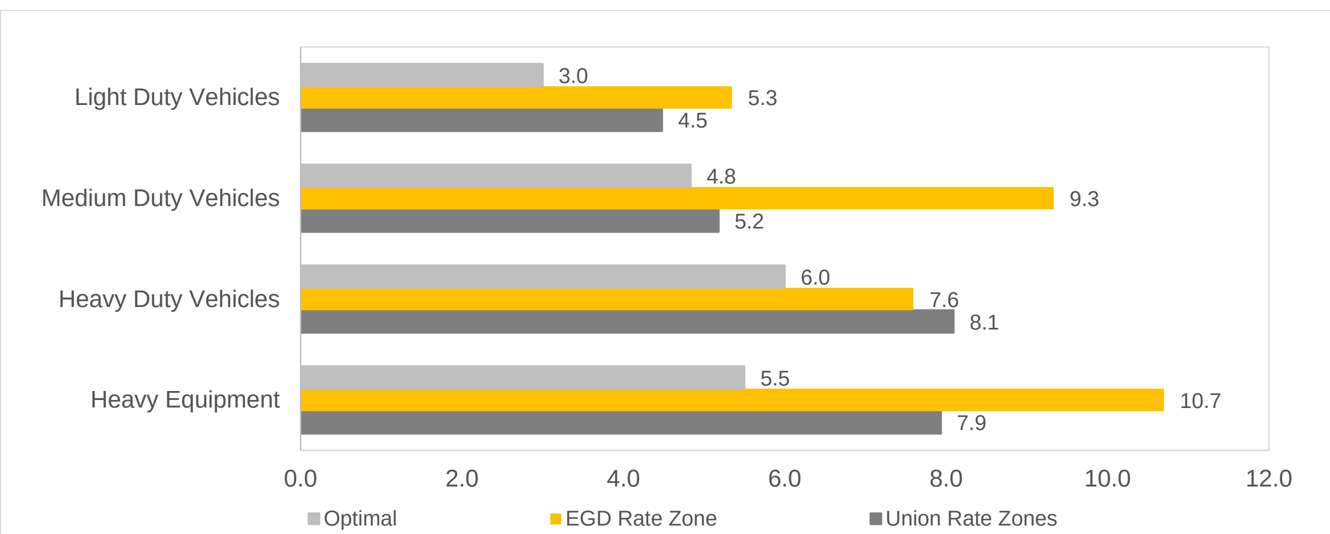

Figure 5.7-2: EGI Average Vehicle Age

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Depending on a vehicle's weight class, analysis indicates that average maintenance costs exceed the market value of a light-duty vehicle at an approximate age of five to seven years or 160,000 kilometres. For medium-duty vehicles, this point of replacement occurs at approximately seven to 12 years old or 175,000 kilometres. For heavy duty vehicles, this occurs at 12 years old or 350,000 kilometres.

As **Figure 5.7-2** shows, the average age of fleet assets for both rate zones is higher than the optimal age, highlighting the need for increased investments to ensure that fleet replacements continue to occur as per the replacement strategy. As part of integration activities to align fleet inventories and classifications, a single classification standard in line with broader industry standards was chosen and is now being applied across the enterprise.

5.7.5.3. Risk and Opportunity

Fleet vehicles and heavy equipment assets (see **Section 5.7.6**) have similar risks and opportunities. There are a number of consequences to EGI when vehicles and equipment exceed their useful life:

- Aging asset condition, resulting in decreased safety and reliability
- Increased maintenance costs
- Increased downtime (vehicles are more frequently in the shop for maintenance), decreasing employee productivity
- Operational safety concerns potentially affecting employees, contractors and the public when vehicles fail
- Increased downtime due to repairs can reduce overall productivity and can affect EGI's ability to serve its customers.
- Equipment that operates beyond its warranty sees an additional increase in maintenance costs (i.e., the cost of repairing certain equipment components that are out of warranty)

Based on the risk assessment analysis, fleet vehicles primarily pose a financial risk to EGI if they are not maintained or replaced as needed. Maintenance costs increase beyond the vehicle warranty and productivity is reduced due to increased downtime as a result of more frequent maintenance activities. On-road failure would also impact public safety and decrease productivity. Decreased productivity can affect the ability to serve our customers, potentially creating a risk to customer satisfaction.

5.7.5.4. Strategy Outcomes

Starting in 2020, the EGI Fleet and Equipment department will leverage the Fleet Category Management (FCM; also known as Supply Chain) organization to arrange the purchasing of all vehicle and heavy equipment assets, in alignment with Enbridge's enterprise supply chain strategy. The FCM team is accountable to source and purchase all vehicle and equipment assets to support EGI business operations (this strategy does not include tools purchases).

As part of integration activities, a comparison of EGD and Union rate zone assets was conducted. Analysis shows the asset hierarchy is very similar for both. Variances are explained by differences in work procedures.

As utility integration efforts continue to align workforce and work processes/procedures, the Fleet and Equipment department will adapt their inventories to support this change. The impacts of such changes may result in a new approach to vehicle standards, as well as equipment and tool use. Regardless of change initiatives in flight, transformation of the Fleet and Equipment asset base will likely require many years to complete.

The optimal replacement strategy for all fleet vehicles is determined by the lowest cost of a vehicle or equipment's lifetime. The lowest cost is determined by analyzing cost curves for maintenance. Asset replacement decisions are evaluated against the optimal replacement analysis plus age, mileage, hours of use, condition, risk of failure and functional requirements. Each asset is ranked and evaluated annually. In general, the optimal replacement point is determined when the maintenance costs begin to exceed the market value of the asset.

Table 5.7-3 shows the replacement cycle for light duty vehicles.

Table 5.7-3: Replacement Cycle for Light-Duty Vehicles

Class	Gross Vehicle Weight Rating	Replacement Cycle (Months)	Replacement Cycle (Kilometres)
1	0 – 6,000 lbs.	60	160,000
2	6,001 - 10,000 lbs.	72	160,000
3	10,001 - 14,000 lbs.	84	175,000

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Table 5.7-4 shows the replacement cycle for medium duty vehicles.

Table 5.7-4: Replacement Cycle for Medium-Duty Vehicles

Class	Gross Vehicle Weight Rating	Replacement Cycle (Months)	Replacement Cycle (Kilometres)
4	14,001 - 16,000 lbs.	84	175,000
5	16,001 - 19,500 lbs.	120	175,000
6	19,501 - 26,000 lbs.	144	350,000

Table 5.7-5 shows the replacement cycle for heavy duty vehicles.

Table 5.7-5: Replacement Cycle for Heavy-Duty Vehicles

Class	Gross Vehicle Weight Rating	Replacement Cycle (Months)	Replacement Cycle (Kilometres)
7	26,001 - 33,000 lbs.	144	350,000
8	33,001 - 150,000 lbs.	144	350,000

5.7.6 Heavy Equipment

Heavy equipment is described as off-road building equipment; at EGI this asset subclass primarily consists of backhoes, trailers, compressors, forklifts, welding machines and directional drilling equipment. These assets are grouped together due to similarities in condition methodology and approach.

5.7.6.1. Condition Methodology

The analysis of heavy equipment assets used the same condition methodology for fleet vehicles. See **Section 5.7.5.1.**

5.7.6.2. Condition Findings

The average age for heavy equipment is 10.7 years for the EGD rate zone and 7.9 years for the Union rate zones. Analysis indicates that average maintenance costs exceed the market value of heavy equipment at approximately 12 years old (see **Figure 5.7-2**).

Based on Fleet Management system reporting, industry standards and asset assessment trends, the typical average useful life threshold for heavy equipment is at approximately 12 years of age (or approximately 7,000 service hours). This threshold is used as a guide for further detailed inspections. The condition of these units is thoroughly assessed when they reach their useful life threshold to make an informed decision to replace or refurbish the asset for continued service.

As **Figure 5.7-2** shows, the average age of heavy equipment assets for both rate zones is higher than the optimal age, highlighting the need for increased investments to ensure that heavy equipment replacements continue to occur as per the replacement strategy.

5.7.6.3. Risk and Opportunity

See **Section 5.7.5.3.**

5.7.6.4. Strategy Outcomes

EGI has an annual heavy equipment program based on average historical spending and is driven by proactively replacing assets based on detailed physical condition assessments and reactively acquiring new equipment based on business needs. Depending on evaluation results, there could be a decision to refurbish the asset instead of replacement. The current replacement cycle for heavy equipment is 144 months (12 years).

5.7.7 Tools

EGI uses a wide variety of tools, including electric air movers, drills, concrete saws, clay spades, gas surveyors, personal gas monitors, pipe locators, pipe squeeze-off tools, shoring boxes, torpedoes, grease guns, etc. In total, there are approximately 11,000 tools currently in use.

Due to the variety of tools and equipment, several inspection and calibration frequencies are in place. The general condition and functionality of tools are assessed by the operator prior to use and during scheduled inspections and calibrations. Deficiencies identified are reported where an assessment of the repair and replacement costs is completed to determine the appropriate course of action.

5.7.7.1. Risk and Opportunity

Not maintaining EGI's tool population presents both a safety risk to employees and customers during operation. In addition, productivity will decline due to increased downtime as a result of using inadequate tools, posing both a financial risk to EGI as well as impacting customer satisfaction.

5.7.7.2. Strategy Outcomes

The strategy for tools is to establish an annual replacement program based on average historical spend. The program is reactive in nature and driven by replacing/acquiring tools that are:

- Showing signs of wear and tear, or are broken and not repairable
- Stolen or lost
- Deemed obsolete by the manufacturer
- No longer approved for use due to evolving engineering standards and practices
- Required by EGI Operations departments for business function

Tools and equipment deemed obsolete and/or are no longer approved for use are removed from service, decommissioned and approved replacement assets are acquired.

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5.7.8 Fleet and Equipment Capital Expenditure Summary

EGI has spent an average of $8M and $9M annually in the EGD and Union rate zones respectively for the Fleet and Equipment asset class. The total average capital spend is forecasted to be $12M (EGD RZ) and $13M (Union RZ) as summarized in **Table 5.7-6** and **Table 5.7-7**. Fleet and Equipment capital is further summarized as part of EGI's total five-year capital plan in **Section 6.**

Table 5.7-6: Fleet and Equipment Capital Summary ($ Thousands) – EGD Rate Zone

Program/Project Name	2021	2022	2023	2024	2025	Five-year Forecast
Vehicles	5,938	6,065	6,471	6,434	6,993	31,902
Heavy Work Equipment	3,827	3,909	4,170	4,146	4,507	20,560
Tools	1,099	1,119	1,205	1,195	1,295	5,913
EGD Rate Zone Total	**10,864**	**11,094**	**11,847**	**11,775**	**12,796**	**58,375**

Table 5.7-7: Fleet and Equipment Capital Summary ($ Thousands) – Union Rate Zones

Program/Project Name	2021	2022	2023	2024	2025	Five-year Forecast
Vehicles	6,048	6,170	6,589	6,606	7,176	32,590
Heavy Work Equipment	3,734	3,809	4,068	4,078	4,430	20,119
Tools	1,944	1,972	2,119	2,112	2,281	10,427
Union Rate Zones Total	**11,727**	**11,951**	**12,776**	**12,796**	**13,887**	**63,137**

Assumptions:

- *Vehicle and heavy equipment forecasts are based on the current fleet profile of 60.18% vehicles and 39.82% heavy equipment.*
- *The Tools forecast is based on historical spend values and an annual increase of 2.0% to account for inflation.*

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5.8 Technology and Information Services (TIS)

The Technology and Information Services (TIS) asset class includes the Hardware, Software and Communications subclasses (**Figure 5.8-1**).

The Hardware asset subclass has three types of assets: laptops/desktops, desktop sustainment equipment and core & security infrastructure hardware. Desktop sustainment equipment includes the additional components that equip the end user, such as keyboards, telephone headsets, computer monitors, audio/visual equipment, telephony, printers, scanners and ergonomic equipment.

Core and security infrastructure hardware assets include network components, servers, security appliances and telephony equipment. Network hardware consists of routers, switches, hubs, firewalls, devices required to maintain voice communication and video conferencing networks. Servers consist of devices that operate EGI's applications and store data. Security hardware refers to equipment used to protect control systems, business applications, computer infrastructure and data networks. Telephony equipment includes routers, switches and desk telephones.

The lifespans of hardware assets typically range between four and seven years depending on the device. As the devices within each group vary in age, a portion of all the hardware assets are upgraded each year to ensure ongoing operational reliability.

Software assets consist of packaged applications (purchased from and generally supported by a vendor), developed applications (custom built in-house) and application infrastructure software (foundational infrastructure software and tools for applications).

Communications assets include mobile phones and field devices (such as GPS devices, push-to-talk radios, leak survey field technology and truck modems).

TIS applications and related technology work activities are driven by a combination of enhancement projects and life cycle upgrades and/or replacements. The over-arching objective is to ensure that TIS applications and related technologies provide desired functionality, perform efficiently and are usable, reliable, maintainable and compatible with other applications and technologies, while ensuring the required standard of security.

Effort is made to ensure the needs of each business area are met, including considerations related to legislative compliance, regulatory orders, and financial accounting and reporting requirements.

Investments are developed for each TIS investment and are prioritized using compliance, life cycle, financial and strategic drivers.

During the TIS application life cycle, technology and design reviews are held to ensure new systems are implemented in the most cost-effective manner, using standard tools and proper security coding practices.

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5.8.1 Technology and Information Services Objectives

The overall goal of the TIS asset class is to meet EGI's information technology needs, established in response to asset, process and system objectives and concerns. The response to these needs and the decision to undertake a solution is guided by the TIS asset class objectives listed in **Table 5.8-1**.

Table 5.8-1: TIS Asset Class Objectives

Asset Class Objectives	Description
Functionality	Ensure solutions provided are fit for purpose based on business requirements and value.
Reliability	Maintain the ability of the asset to perform its required function over its useful life.
Security	Ensure controls and checks are in place for applications/software/data that protects the asset against threats and vulnerabilities.
Availability	Ensure that hardware, devices and/or applications/software are readily available for use when required and will work as intended.
Supportability	Maintain the ability of support and service staff to install, configure and monitor assets, identify exceptions and faults, isolate defects/issues preventing the asset from functioning as expected and provide maintenance services.
Maintainability	Continually ensure that assets are maintainable to isolate and correct defects, prevent unexpected breakdowns, maximize their useful life, meet new business requirements and simplify future maintenance procedures.
Continuous Improvement	Continuously evolve the understanding of condition and risk for TIS assets and use risk, cost and performance information to drive asset-related decisions.

The performance measures for the TIS asset class are as follows:

- Number of application/system outages
- Number of defects
- Number of vulnerabilities and security-related incidents
- Adherence to security policies and scorecard objectives
- Security patching levels
- Overall system and application availability metrics
- Number of hardware incidents
- Number of change and enhancement requests
- Incident response time and resolution time met

To achieve the Technology and Information Services asset class objectives listed in **Table 5.8-1**, asset investment decisions are governed by the life cycle management strategies outlined in **Table 4.1-1**.

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5.8.2 Technology and Information Services Hierarchy

The asset subclass hierarchy for the Technology and Information Services asset class is illustrated in **Figure 5.8-1**.

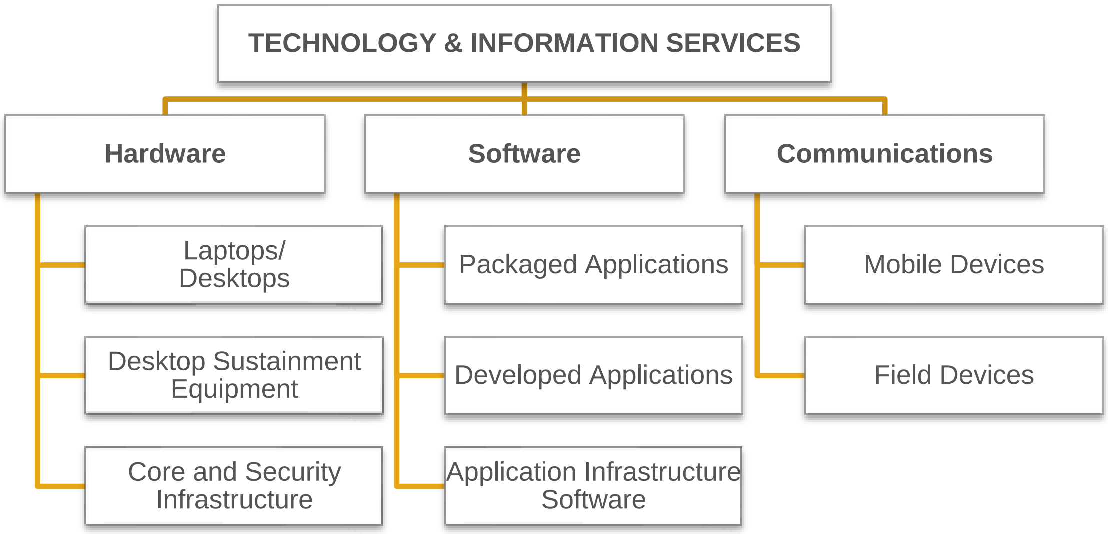

Figure 5.8-1: Technology and Information Services Hierarchy

5.8.3 Technology and Information Services Inventory

The TIS asset class inventory is presented in **Table 5.8-2.**

Table 5.8-2: TIS Asset Class Inventory

Asset	EGD Rate Zone	Union Rate Zones
Hardware		
Laptops and Desktops	2,050	2,003
Desktop Sustainment Equipment	N/A*	N/A*
Core and Security Infrastructure	2437	2862
Software		
Packaged Applications	199	35
Developed Applications	76	28
Application Infrastructure Software	11	19
Communications		
Mobile Phones	2,463	1,845
Field Devices	1,070	832

**The inventory count for Desktop Sustainment Equipment assets is not recorded.*

.

5.8.4 Technology and Information Services Condition and Strategy Overview

Asset Subclass	Avg. Age (Year)	Condition	Risk / Opportunity	Maintenance Strategy	Replacement / Renewal Strategy
Laptops and Desktops	2	Laptops and desktops tend to experience performance issues and failures in their fourth year of operation (constituting approximately 30% of these assets). The condition of laptops and desktops is not proactively monitored.	**Financial Risk**: Aging assets result in a reduction in productivity and increase in maintenance costs.	Laptops are replaced proactively based on age and warranty status.	**Laptop/Desktop Renewal Strategy**: EGI's strategy is to replace laptops and desktops every four years. For the majority of their life (three years), these assets are under warranty. This strategy allows for a short extended use of the asset past warranty expiration (one additional year) prior to replacement.
Desktop Sustainment Equipment	N/A	The condition and health of desktop sustainment equipment is not proactively monitored.	**Employee and Contractor Safety Risk**: Inadequate desktop sustainment equipment compromises the health and safety of employees who require specific equipment for ergonomic purposes. **Financial Risks**: Inability to meet business needs and requirements, reducing overall productivity **Operational Risk**: Inadequate or lack of desktop sustainment equipment required for new and existing employees	Reactive maintenance as required through service requests.	**Desktop Sustainment Equipment Strategy**: Desktop sustainment equipment is provided on an as-needed basis. The replacement of desktop sustainment equipment is based on the following circumstances: • Equipment is damaged, broken or malfunctioning. • Equipment is required based on employee ergonomic assessments. • Equipment is required for new employee and contractor hires.
Core and Security Infrastructure	3	Servers and appliances tend to experience performance issues and failures in their fifth year of operation (constituting approximately 30% of these assets).	**Financial Risk**: Aging assets result in a reduction in productivity, a risk of increase in hardware incidents and outages and an increase in maintenance costs.	Servers and appliances are replaced proactively based on age, compliance and warranty status.	**Core Infrastructure and Security Renewal Strategy**: EGI's strategy is to replace servers and appliances for core infrastructure and security every five years. For the majority of their life (four years), these assets are under warranty and this strategy allows for a short extended use of the asset past warranty expiration (one additional year) prior to replacement.
Packaged and Developed Applications	10	The condition of packaged and developed applications is evaluated on the following: • Ability to meet business requirements • Hardware to meet vendor support requirements • Software to meet vendor support life cycle (for packaged applications) • Ability to enhance and support existing applications See **Table 5.8-3** and **Table 5.8-4** for the condition findings for this subclass.	**Financial Risks**: • Inability to meet business needs and requirements, reducing overall productivity • Inability to meet financial and reporting compliance requirements • Increased maintenance costs due to reactively addressing required software and hardware repairs **Operational Risk**: Extended application and system outages.	Maintenance releases and software defect fixes are rolled out regularly as a means of reactively maintaining the performance of packaged and developed applications.	**Developed and Packaged Applications Renewal Strategy**: The replacement of developed and packaged applications is dependent on changing business requirements or due to an application solution becoming unsupported by its vendor.
Application Infrastructure Software	12	The condition of application infrastructure software is evaluated on the following: • Software to meet vendor support refresh life cycles • Ability to support the key foundational software required for in-use/predicted applications See **Table 5.8 5** for the condition findings for this subclass.	**Reputational Risk**: cybersecurity exposure due to the inability to apply required security patches may potentially lead to negative reputational impacts for EGI if any breaches occur.	Maintenance is reactive - performance issues or software defects are addressed as they are identified.	**Application Infrastructure Renewal Strategy**: A proactive replacement/refresh strategy is in place, driven by forecasted changes to existing software products and business requirements.
Mobile Devices	2	The condition of mobile devices is not proactively monitored.	**Employee and Contractor Safety Risk; Public Health and Safety Risk**: Inadequate (or the lack of) mobile devices hinder the ability of employees to respond to emergency field situations, which may contribute to the severity of an incident and potentially endanger lives of the public. **Operational Risk**: Inadequate (or the lack of) mobile devices hinder the ability of employees to resolve off-hours, on-call situations, which may affect the reliable and safe operations of EGI's systems and networks.	Mobile devices are maintained internally to address performance issues. Damaged devices are repaired/replaced on an as-needed basis within the three-year replacement window.	**Mobile Device Renewal Strategy**: EGI follows industry best practices for replacing mobile devices at two to three years, which aligns with the smartphone manufacturers' release cycles and typical data plan contracts.
Field Devices	4	The condition of field devices is not proactively monitored. Due to exposure to tough working conditions, field devices experience significant wear and tear. (Breakage and performance issues generally occur in their fourth year of use).	**Employee and Contractor Safety Risk; Public Health and Safety Risk**: Inadequate (or the lack of) field devices hinders the ability of employees to respond to emergency field situations due to device unavailability **Operational Risk**: Inadequate (or the lack of) field devices may result in increased time travelling between office and job sites	Maintenance repairs and replacements are performed as needed through service requests.	**Field Device Renewal Strategy**: Most field devices, such as ruggedized laptops, Toughbooks and Toughpads, have a four-year proactive replacement strategy driven by industry best practices. Some assets, such as truck modems, are replaced as needed.

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5.8.5 Laptops and Desktops

This TIS asset subclass includes over 4,000 laptops and desktops. The majority of employees and contractors rely heavily on the day-to-day performance of their laptops and desktops to perform daily tasks and to access company communications, applications and resources on EGI's networks and systems.

Laptops and desktops are covered by the manufacturer's warranty for three years.

5.8.5.1. Condition Methodology

The condition of laptops and desktops is not proactively monitored. If these assets experience failures or signs of operating issues, a request for support and resolution is logged through ServiceNow, the TIS Service Management system. All laptops and desktops are labelled with a unique asset tag number to identify the asset for tracking purposes. The ServiceNow request is mapped to the user's unique asset tag number, which ensures the necessary remediation work is completed on the appropriate asset.

5.8.5.2. Condition Findings

Laptops and desktops tend to experience performance issues and failures in their fourth year of operation, a year after their warranty expires. Laptop failures can occur for a variety of reasons, including complete hard drive failures, processor board failures, memory failures and significantly degraded performance.

In 2019, 80% of laptops and desktops were replaced in a significant initiative to move to the Windows 10 operating system due to Windows 7 being at end-of-life. This resulted in an almost 40% reduction in total logged incidents by users, demonstrating that replacing these assets before problems start to occur reduces the number of incidents reported.

5.8.5.3. Risk and Opportunity

The major risk identified for laptops and desktops is financial risk–aging assets result in a reduction in productivity and increase in maintenance costs. There are a number of consequences if these assets are not replaced soon after warranty expiry:

- Replacement parts for existing hardware become obsolete, resulting in an asset that is more expensive to repair.
- Existing hardware is not compatible with newer operating systems and applications, resulting in an asset with reduced functionality.
- Maintenance costs can become excessive after warranty expiry.
- There is an overall reduction in productivity due to aging assets.

5.8.5.4. Strategy Outcomes

EGI's renewal strategy is to replace laptops and desktops every four years. Industry best practice suggests replacing laptops and desktops every three years, in line with its warranty (also three years). EGI's strategy allows for one additional year past warranty expiration prior to replacement, reducing the overall capital cost of the laptop refresh cycle.

Defective or poorly performing laptops that are out of warranty are repaired if the problem is quickly determined and if the repair can be done cost-effectively. Otherwise, the device is replaced. The impact of repairing an out-of-warranty device includes productivity loss to the end user, technician repair time and the cost of unbudgeted parts for repair. As more and more out-of-warranty devices fail over time, EGI's replacement strategy is most effective at balancing risk, cost and performance for this group of assets.

The four-year replacement policy for laptops and desktops has been in place for the last 20 years and has proven to be sufficient and manageable from a resourcing perspective.

EGI follows both a proactive and reactive maintenance strategy for these assets, managed through ServiceNow.

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5.8.6 Desktop Sustainment Equipment

Desktop sustainment assets include all TIS hardware equipment required for business operations. Audio/visual equipment, printers, monitors, keyboards, mice, privacy screens and headsets are some examples of desktop sustainment equipment.

5.8.6.1. Condition Methodology

The condition of desktop sustainment equipment is evaluated on the following:

- New hire onboarding information
- Hardware incident requests
- Feedback and requests from ergonomic specialists and business users

The condition and health of desktop sustainment equipment is not proactively monitored.

5.8.6.2. Condition Findings

Annually, there are approximately:

- 350-400 ergonomic-related requests requiring ergonomic equipment
- 400-450 onboarding requests requiring desktop sustainment equipment to support new employees/contractors
- 650-700 hardware incidents

5.8.6.3. Risk and Opportunity

The major risks identified for desktop sustainment equipment are:

- **Employee and Contractor Safety Risk**: Inadequate desktop sustainment equipment may compromise the health and safety of employees who require specific equipment for ergonomic purposes.
- **Operational Risk**: Inadequate or lack of desktop sustainment equipment required for new and existing employees results in a reduction in productivity.

5.8.6.4. Strategy Outcomes

Desktop sustainment equipment is provided on an as-needed, reactive basis. Desktop sustainment equipment is issued based on the following:

- Equipment is damaged, broken or malfunctioning.
- Equipment is required based on an ergonomic assessment.
- Equipment is required for new employee and contractor hires.

EGI uses historical spend to project the capital requirements for the replacement of desktop sustainment equipment.

5.8.7 Core and Security Infrastructure

5.8.7.1. Condition Methodology

Servers and appliances tend to experience performance issues and failures in their fifth year of operation (constituting approximately 30% of these assets). The physical condition of core and security hardware is not proactively monitored. If these assets experience failures or signs of operating issues, the hardware vendor is contacted for support and an incident ticket is logged through ServiceNow.

5.8.7.2. Condition Findings

Core and security hardware asset failures can occur for a variety of reasons, including hard drive failures, processor failures, memory failures and significantly degraded performance.

5.8.7.3. Risk and Opportunity

The major risk identified for core and security hardware failures is financial risk–aging assets result in a reduction in productivity due to incidents and outages and increase in maintenance costs. There are a number of consequences if these assets are not replaced soon after warranty expiry:

- Existing hardware is not compatible with newer operating systems and applications, resulting in an asset with reduced functionality.
- Maintenance costs can become excessive after warranty expiry.

5.8.7.4. Strategy Outcomes

EGI's strategy is to replace servers and appliances for core infrastructure and security hardware every five years. For most of their life (four years), these assets are under warranty. This strategy allows for a short extended use of the asset past warranty expiration (one additional year) prior to replacement.

Defective or poorly performing servers and appliances that are out of warranty are repaired by the vendor through hardware maintenance contracts following warranty expiry. The impact of repairing an out-of-warranty device includes potential productivity loss to the end user due to applications being unavailable and the costs required for the hardware maintenance contracts. As more and more devices fail over time, EGI's replacement strategy is most effective at balancing performance, cost and risk for this group of assets.

EGI follows both a proactive and reactive maintenance strategy for these assets, managed through ServiceNow and the hardware vendor(s).

5.8.8 Packaged and Developed Applications

TIS assets include a number of key applications that provide critical functionality to EGI employees and customers, contributing to the support and growth of its natural gas storage, transmission and distribution businesses. Key TIS applications also rely on ancillary systems that have been added over time to provide additional functionality as business needs change and grow.

Packaged applications, also known as Commercial-off-the-Shelf (COTS) software, are solutions purchased from and primarily supported by a vendor; support includes software version upgrades. Software upgrades are required for the application to stay current and supported. For some solutions, EGI provides functionality and enhancement requests and the vendor provides additional software releases to address these requests. The age range of packaged applications extends out as far as 15 years; however, the majority are within a 10-year range.

Developed applications are custom-built solutions by EGI to meet business requirements. This generally occurs when no packaged solutions are available to support business requirements. The age range for developed applications can extend out as far as 20 years before a life cycle replacement or significant upgrade occurs. Technology upgrades and enhancements may occur regularly for internally developed solutions.

5.8.8.1. Condition Methodology

The condition of packaged and developed applications is evaluated on the following:

- Ability to meet business requirements
- Hardware to meet vendor support requirements
- Software to meet vendor support life cycle (for packaged applications)
- Ability to enhance and support existing applications

5.8.8.2. Condition Findings

Table 5.8-3 summarizes the key packaged applications used at EGI and outlines their current state and condition. Each rate zone continues to operate some systems. Over time, most systems will be integrated. After the systems are integrated, their maintenance costs will be allocated to the rate zones.

Table 5.8-3: Application State – Key Packaged Applications[11]

Application	Application Overview	Age (Years)	Application State
AutoSol Communication Manager (UG)	Polling engine application for reading measurement information	15	Hardware is currently under warranty. Software is current and supported.
Corrosion Survey Management System (CSMS)	Application for leak survey inspection-related work	4	The solution is built on eGIS, which is being upgraded in 2020. The application software will be upgraded in 2020-2021.
Corrosion Survey (DNV GL SynerGi Pipeline)	Pipeline integrity software used in the Union rate zones for scheduling, tracking and field collection of pipeline risk management data	7	Software update completed in 2018.
Customer Information System (CIS)	Customer care and billing applications (SAP CIS and Banner)	9	CIS applications used in both rate zones will be migrated to a SAP cloud-based solution in 2021 as part of EGI integration.

[11] *Copperleaf C55 is not listed as it is managed by Corporate Services.*

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Application	Application Overview	Age (Years)	Application State
EGI Extranet	EGI external website for the EGD rate zone with self-service capabilities	3	Hardware was replaced in 2017/2018. Rewrite and foundational software upgrade occurred in 2017/2018. This application is being integrated with the uniongas.com extranet in 2021.
Geographic Information System (eGIS)	Application for developing geographic views of EGD rate zone asset data	7	Hardware was replaced in 2020. Software was upgraded in 2020.
GIS Suite - G/Technology (Hexagon)	Contains spatial and attribute information related to UG rate zone underground assets	6	Application is being upgraded in 2020 to maintain supportability.
GMAS	Collection and validation system for measurement information in the Union rate zones	20	Hardware is currently under warranty. Software is current and supported.
ITRONFCS	Used to facilitate the meter reading process in the Union rate zones	1	Software was upgraded in 2019.
Leak Survey Management System (LSMS)	Application for leak survey inspection-related work	5	The solution is built on eGIS, which is being upgraded in 2020. The application software will be upgraded in 2020-2021.
Meter Reading System (MVRS)	Application for storing manually-gathered meter readings and meter maintenance information	1	The hardware and application software were upgraded in 2019. This application will be integrated with the ITRONFCS solution as part of EGI integration in 2021.
PIMSlider	Application for analyzing asset condition data and the optimal lifespan of assets	4	Hardware is currently under warranty. Software is current and supported.
Powerspring (formerly Metretek)	Application providing automated meter readings for large volume customers	3	Hardware and software were upgraded to current and supported versions in 2017.
ProjectWise	Managed environment for EGI employees in the Union rate zones to deposit, store, retrieve and allow for the disposition of engineering records	4	Application is being upgraded in 2020 to maintain support.
PureConnect	Call centre application for call management in the Union rate zones	1	Software was last upgraded in 2019 to the current version. An annual upgrade is performed to stay current. Hardware was replaced in 2018.
SCADA	Supervisory control and data acquisition systems that monitor and control underground transmission pipelines	1	Hardware was upgraded in 2019 as part of the GDS control centre migration and SCADA consolidation. Software is being upgraded in 2020.
Service Suite (Advantex)	Electronic planning and dispatch application for the Union rate zones	1	This application is to be replaced by the integrated Work and Asset Management solution.
Teldig	Locate-tracking application used through Ontario One Call	7	Hardware was upgraded in 2019. Application software was upgraded in 2019.

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Application	Application Overview	Age (Years)	Application State
uniongas.com	EGI external website for the Union rate zones with self-service capabilities		This application is being integrated with the EGD rate zone extranet in 2021.
Work and Asset Management (WAMS)	Application to manage work and assets	3	Hardware will upgraded in 2020. This application is to be replaced by the Enbridge Unify solution.

Table 5.8-4 summarizes the key developed applications used at EGI and outlines their current state and condition.

Table 5.8-4: Application State – Key Developed Applications

Application	Application Overview	Age (Years)	Application State
Capital and O&M Management (COMMS)	Application suite for managing EGI capital investments	10	Hardware is currently under warranty. Software was upgraded in 2018.
Classify Allocation Report and Exchange (CARE)	Nominations and scheduling system for gas storage and transportation	25	Hardware is currently under warranty. Software is current and supported.
Construction Administration Records System (CARS)	Application managing construction work orders for new customer service lateral attachments	20	This application is to be replaced by the Enbridge Unify solution in 2023.
Contrax	Application used to create, renew, manage and bill non-cycle large volume customers (Union RZ)	1	Hardware is currently under warranty. Software is current and supported.
Cross Bore Risk Mitigation	Analytics tool used to assess the probability of cross bores	1	Hardware is currently under warranty. Software is current and supported.
Customer Connections Worksuite	Application for managing Customer Connections information	5	Hardware is currently under warranty. Software is current and supported.
eApp	Tool used to submit natural gas services requests online	10	This application is being integrated with the getConnected application used in the Union rate zones in 2021 as part of EGI integration.
Energy Cost Reporting (EnCore)	Application used to develop cost models for energy supply	6	Hardware is currently under warranty. Software is current and supported.
EnTrac	Management software for large volume and direct purchase contracts	14	Hardware will be out of warranty in 2021. Software is current and supported.
Field Record Access (FRA)	Application used to locate asset information	1	The solution is built on eGIS, which is being upgraded in 2020. Newly implemented in 2020; replaced the aging Datapak application.
Finance Business Analysis (FBA)	Data warehouse for reconciliation of customer consumption	5	Hardware is currently under warranty. Software is current and supported.
GetConnected	Tool used to submit natural gas services requests online	10	This application is being integrated with the eApp application used in the EGD rate zone in 2021 as part of EGI integration.
iViewer	Image repository for as as-laid drawings, scans of service tickets and field notes	10	Hardware is currently under warranty. Application software is being upgraded in 2020 to maintain support.

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Application	Application Overview	Age (Years)	Application State
Land Management (rowAMPS)	Application to manage land/property and municipal taxation work	3	Cloud solution as a service offering; implemented in 2017.
Revenue Analysis and Volume Estimation (RAVE)	Application for volumetric analysis, estimation and budgeting	16	Hardware is currently under warranty. Software is current and supported.
Unbundled Rate Compliance (URICA)	Application to request and track unbundled services as per Natural Gas Electricity Interface Review (NGEIR) direction	13	Hardware is currently under warranty. Software is current and supported.
Unionline	Secure web-based tool providing online services to contract customers	20	Hardware is currently under warranty. Software is current and supported.

5.8.8.3. Risk and Opportunity

The major risks identified for packaged and developed applications are:

- **Financial Risk**: Unplanned software outages may compromise EGI's ability to meet business needs and requirements, reducing overall productivity, and may compromise EGI's ability to meet financial and reporting compliance requirements. Maintenance costs may increase due to reactively addressing required software and hardware repairs.
- **Operational Risk**: Inadequate (or the lack of) applications required for employees to complete assigned tasks may contribute to productivity loss.
- **Reputational Risk**: cybersecurity exposure due to the inability to apply required security patches may potentially lead to negative reputational impacts for EGI if any breaches occur.

5.8.8.4. Strategy Outcomes

The replacement strategy for packaged applications is driven by vendor release schedules specific to each application and changes in business requirements. A replacement and/or upgrade can also occur due to the vendor discontinuing software support or application enhancements.

The replacement strategy for developed applications is driven by forecasted requirements for the business. Maintenance releases and software defect fixes are rolled out regularly to reactively maintain the performance of the application. Major enhancements and renewals are implemented for projected new or changing business requirements.

Applications are replaced when business requirements change or when a vendor ceases support for the application. EGI integration will drive a number of application replacements and migrations during the 2021-2023 timeline.

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5.8.9 Application Infrastructure Software

The Application Infrastructure Software asset subclass encompasses software products and tools that support and serve as the platform environment for TIS solutions. Some of the key components of this asset subclass include database software used to store data for various applications, application deployment and execution software, integration software used for interfacing between applications and services and reporting tools.

5.8.9.1. Condition Methodology

The condition of application infrastructure software is evaluated on the following:

- Ability to meet the vendor's support life cycle strategy
- Ability to support key foundational software required for business applications

5.8.9.2. Condition Findings

Table 5.8-5 outlines the current age and state of key application infrastructure software used at EGI:

Table 5.8-5: State of Application Infrastructure Software

Application	Application Overview	Age (Years)	Year(s) since last refresh	Application State
DataStage	Extract, transform and load (ETL) integration tool	18	1	Software is current and supported.
Harvest	Source code management software	20	8	Software is supported.
Quality Assurance and Testing Suite	Testing and quality assurance tool suite	17	5	Software is supported.
Microsoft SQL Server	Database management software	21	1	Software is current and supported.
Oracle Database	Database management software	21	3	Upgrade to current version scheduled in 2020-2021.
Oracle Fusion	Integration suite providing interfacing capabilities between applications	8	1	Software is current and supported.
Oracle Golden Gate	Data replication software	5	5	Software is current and supported.
Oracle WebLogix Application Server	Management software for deployment and execution of applications	17	3	Software is current and supported.
SAP Business Objects Reporting Suite	Suite of reporting tools for business reporting and analytics	12	4	Upgrade to current version scheduled for 2020- 2021.
BizTalk	Message queuing and orchestration software for real-time application to application integrations	20	5	Upgrade to current version scheduled for 2021.
Team Foundation Server	Foundational software used for .Net application development	15	8	Upgrade to current version taking place in 2020.

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5.8.9.3. Risk and Opportunity

The risks identified for application infrastructure software is the same as for packaged and developed applications (**Section 5.8.8.3**).

5.8.9.4. Strategy Outcomes

A proactive replacement strategy is in place for application infrastructure software, driven by forecasted changes of existing software applications and business requirements. Maintenance is reactive–performance issues or software defects are addressed as they are identified. The application infrastructure software systems identified for upgrade/renewal in the next three years are:

- Microsoft SQL Server instances and databases
- Oracle Database instances and databases
- Oracle WebLogic application servers and Oracle Fusion integration software
- SAP Business Objects reporting software
- BizTalk integration software
- Team Foundation development platform software

5.8.10 Mobile Devices

Mobile devices consist of smartphones, cell phones and Push-to-Talk radios. The industry best practice to replace mobile devices is two to three years, which aligns with smartphone manufacturers' release cycles, as well as the typical data plan contract.

5.8.10.1. Condition Methodology

The condition of mobile devices is not proactively monitored. If these assets experience failures or signs of operating issues, the user contacts the TIS Service Desk. In addition, the TIS asset class relies on new hire and business needs requests for equipping new mobile device users.

5.8.10.2. Condition Findings

Annually, there are approximately 1,230 mobile device requests, including both normal life cycle replacement and mobile device replacement due to hardware issues.

5.8.10.3. Risk and Opportunity

The major risks identified for mobile device assets are:

- **Employee and Contractor Safety Risk; Public Health and Safety Risk**: Inadequate (or the lack of) mobile devices hinder the ability of employees to respond to emergency field situations, which may contribute to the severity of an incident and potentially endanger lives of the public.
- **Operational Risk**: Inadequate (or the lack of) mobile devices hinder the ability of employees to resolve off-hours, on-call situations, which may affect the reliable and safe operations of EGI's systems and networks.

5.8.10.4. Strategy Outcomes

The TIS asset class strategy for mobile devices is to stay one release cycle behind manufacturer releases as mobile devices are available at much lower cost. As such, mobile devices have a proactive replacement strategy of every three years driven by industry best practice and release cycles.

Mobile devices are reactively maintained to address performance issues and damaged/broken devices on an as-needed basis within the three-year replacement window. Approximately 500 devices are replaced annually as per the refresh strategy.

EGI uses historical spend to project the capital requirements for the replacement of mobile devices.

5.8.11 Field Devices

Field devices include ruggedized laptops, Toughpads and Toughbooks, printers, plotters and multi-function devices, GPS devices and truck modems for signal strengthening.

5.8.11.1. Condition Methodology

The following inputs are used to assess the condition and suitability of field devices:

- Incident requests logged in ServiceNow
- Feedback from end users on field device performance
- Business needs driving field devices requirements

5.8.11.2. Condition Findings

Typically, field devices experience an elevated level of breakage and performance issues by the fourth year of use. Due to exposure to tough working conditions, field devices experience significant wear and tear, requiring maintenance on a frequent and reactive basis.

5.8.11.3. Risk and Opportunity

The major risks identified for field devices are:

- **Employee and Contractor Health and Safety Risk; Public Health and Safety Risk**: Inadequate (or the lack of) field devices hinders the ability of employees to respond to emergency field situations due to device unavailability
- **Operational Risk**: Inadequate (or the lack of) field devices may result in productivity loss due to increased time travelling between office and job sites.

5.8.11.4. Strategy Outcomes

The majority of field devices, such as ruggedized laptops, Toughbooks and Toughpads, have a four-year replacement strategy, based on industry best practices and EGI’s condition experiences. Some assets (such as truck modems) do not have an industry-directed replacement cycle and are reactively replaced as they fail. TIS uses historical spend to project the capital requirements for the replacement of field devices.

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5.8.12 Technology and Information Services Capital Expenditure Summary

EGI has spent an average of $32M and $24M annually in the EGD and Union rate zones respectively for the Technology and Information Services asset class. The total average capital spend is forecasted to be $30M (EGD RZ) and $23M (Union RZ), as summarized in **Table 5.8-6** and **Table 5.8-7**. The TIS capital is further summarized as part of EGI's total five-year capital plan in **Section 6.**

Table 5.8-6: TIS Capital Summary ($ Thousands) – EGD Rate Zone

Program/Project Name	2021	2022	2023	2024	2025	Five-Year Forecast
TIS Infrastructure	4,882	8,225	5,816	10,513	6,132	35,568
Business Solutions	23,456	31,215	25,027	16,828	18,632	115,158
EGD Rate Zone Total	**28,216**	**39,365**	**30,796**	**27,284**	**25,109**	**150,770**

Table 5.8-7: TIS Capital Summary ($ Thousands) – Union Rate Zones

Program/Project Name	2021	2022	2023	2024	2025	Five-Year Forecast
TIS Infrastructure	5,062	9,077	6,432	12,684	7,945	41, 201
Business Solutions	6,261	9,109	7,730	24,669	24,972	72,741
Union Rate Zones Total	**11,323**	**18,186**	**14,162**	**37,352**	**32,918**	**113,942**

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6. Summary of Capital Expenditure

6.1 Portfolio Optimization

Using the methodology for optimization outlined in **Section 4**, this section describes the summary of the capital expenditures required to meet EGI's asset management goals and to balance risk, cost and performance. Through careful consideration of the key inputs to the asset investment planning process (risk, customer engagement feedback, resource constraints), this plan provides critical direction for the next five years.

6.1.1 Investment Criteria

In preparation for optimization, comprehensive governance reviews were completed on proposed investments using the following criteria:

- Investment scope met EGI's capitalization policy.
- Investments presented a well-articulated purpose, need and timing aligned with asset class objectives and life cycle management strategies.
- Investment scope definition and alternatives adequately addressed project risks and/or opportunities.
- Investments supported the asset management principles of balancing risk, cost and performance.
- Execution risks were reasonable (resource capacity).
- Initiatives identified as mandatory were justified, based on:
  - Compliance requirements
  - Exceeding a risk limit within EGI's intolerable risk region or Very High risks on the Enbridge Risk Matrix (**Figure 4.1-7**)
  - Third-party relocation driven
  - Program work with sufficient history and risk to warrant continuation
  - Projects that meet the economic feasibility tests in *EBO 188* and *EBO 134*
  - Investments that were already executing with costs continuing into 2021-2025

In total, 1,251 Union rate zone investments and 863 EGD rate zone investments were included in the optimization of the five-year plan. Separate optimizations were run for each rate zone. The initial pre-optimized request for capital is illustrated in **Figure 6.1-1** and **Figure 6.1-2**, generated from the asset investment planning tool (C55).

6.1.2 Capital Considerations

The optimization process is based on EGI management setting a capital constraint or threshold from which a portfolio of work driven by asset needs is defined. The capital constraint is determined based on the defined regulatory framework. Determining the capital constraint involves EGI's Asset Management, Finance and Regulatory departments.

To complete EGI's latest portfolio optimization, the outcome of the MAADs Decision (*EB-2017-0306/EB-2017-0307*) and smoothing the impact to ratepayers were considered when establishing the capital constraint. The MAADs Decision established the Regulatory framework and provided EGI with the approved five-year (2019-2023) annual Incremental Capital Module (ICM) Materiality Threshold, giving EGI access to rate recovery for qualifying capital investments over and above this Materiality Threshold through the OEB's Incremental Capital Module. The 2021 ICM Materiality Threshold formula was used to determine EGI's capital constraint for 2021. For the years 2022 to 2025, the capital constraint was escalated based on the projected growth factor, allowing EGI to balance rate impacts with the utility's obligation to serve and maintain its plant. The capital constraint is inclusive of overheads[12].

EGI's capital spend requirements up to the OEB-approved ICM Materiality Threshold is described as Base Capital. To understand which projects would be considered incremental and potentially ICM-eligible, EGI applied descriptions of Base Capital and Incremental Capital Eligible to all investments for optimization (**Table 6.1-1**):

[12] *Overheads include loadings, Interest During Construction and departmental and labour costs.*

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Table 6.1-1: Base Capital and ICM-eligible Capital Descriptions

Term	Description
Base Capital	• Represents the ongoing capital requirements of the utility to maintain safe and reliable operations and to economically attach new customers and pursue opportunities for innovation • Driven by asset class strategies and programmatic work that has sufficient history and risk to warrant continuation • Supported by existing rates (through depreciation expense, annual price cap index rate increases, or incremental revenues from customer growth)
ICM-eligible Capital	• Represents discrete projects requiring an in-service capital investment of over $10M • Refers to spend driven by asset class strategies and not supported by existing rates • Total incremental spend will include all capital costs associated with the identified project incurred up to the project's in-service year when ICM is requested. • ICM eligibility does not confirm that EGI will seek ICM recovery for these projects.

To optimize the 1,251 Union rate zone investments and 863 EGD rate zone investments, the asset investment planning tool (C55) was used. The capital constraint values were used to set an overall constraint and the optimal capital timing was determined for proposed investments.

6.1.3 Optimization Results

Portfolio optimization considers the most recent approved plan; the initial spend profile is the result of the previous optimization and approved portfolio, with the addition of new investments and updates to existing investments.

For the EGD rate zone, the initial pre-optimized request for capital exceeded the capital constraint in 2021, 2022 and 2024 (**Figure 6.1-1**). For the Union rate zones, the initial pre-optimized request for capital exceeded the capital constraint in all years (**Figure 6.1-2**). It is important to note that while overheads are included with each investment's forecast when the plan is approved, at the time of optimization, overheads are managed as their own annual forecast due to the potential time shifting of investments. Overhead amounts are approximated based on the most recent approved plan at the time of optimization and then refined at the investment level once project timing is confirmed and the plan approved.

The capital plan was optimized from 2021-2025 using the Asset Management Core Process (outlined in **Section 4.2**). The result addresses the organization's asset needs and includes known risks and opportunities requiring action over the next five years.

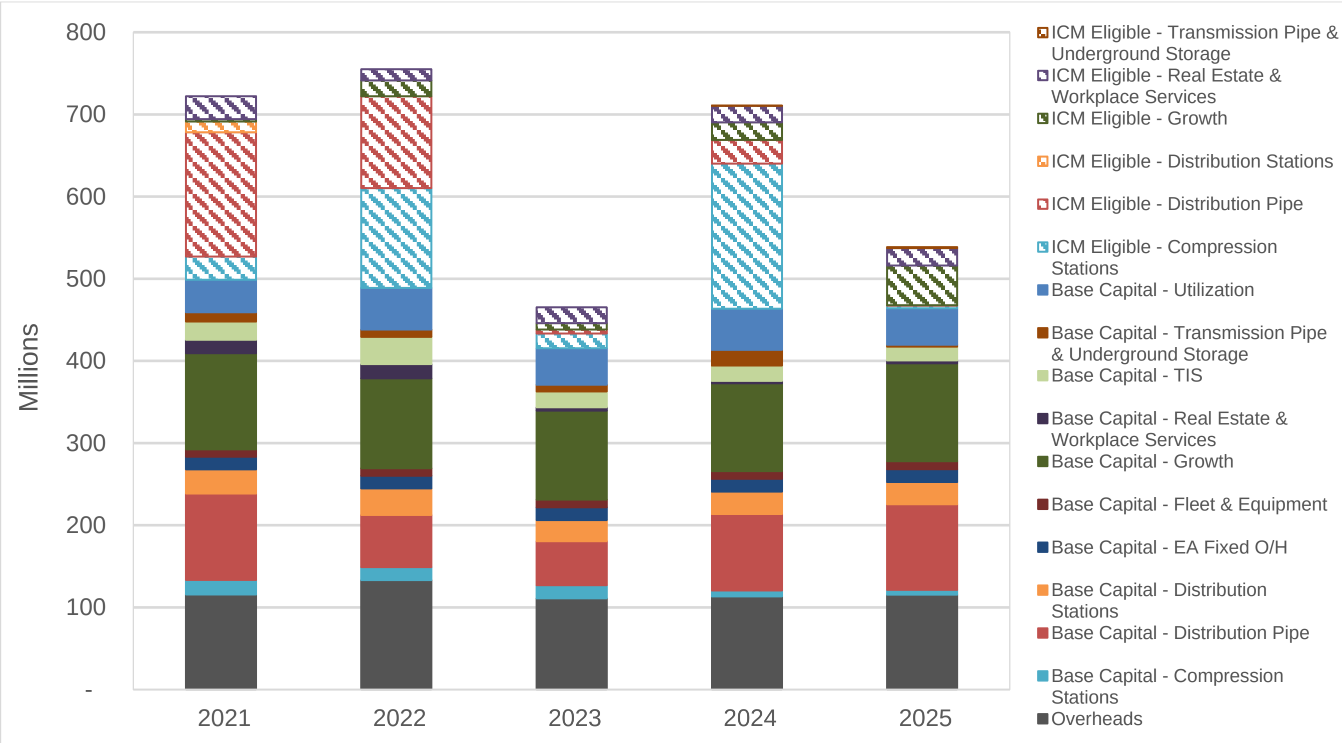

Figure 6.1-1: EGD Rate Zone Pre-Optimized Spend Profile (Capital Expenditure)

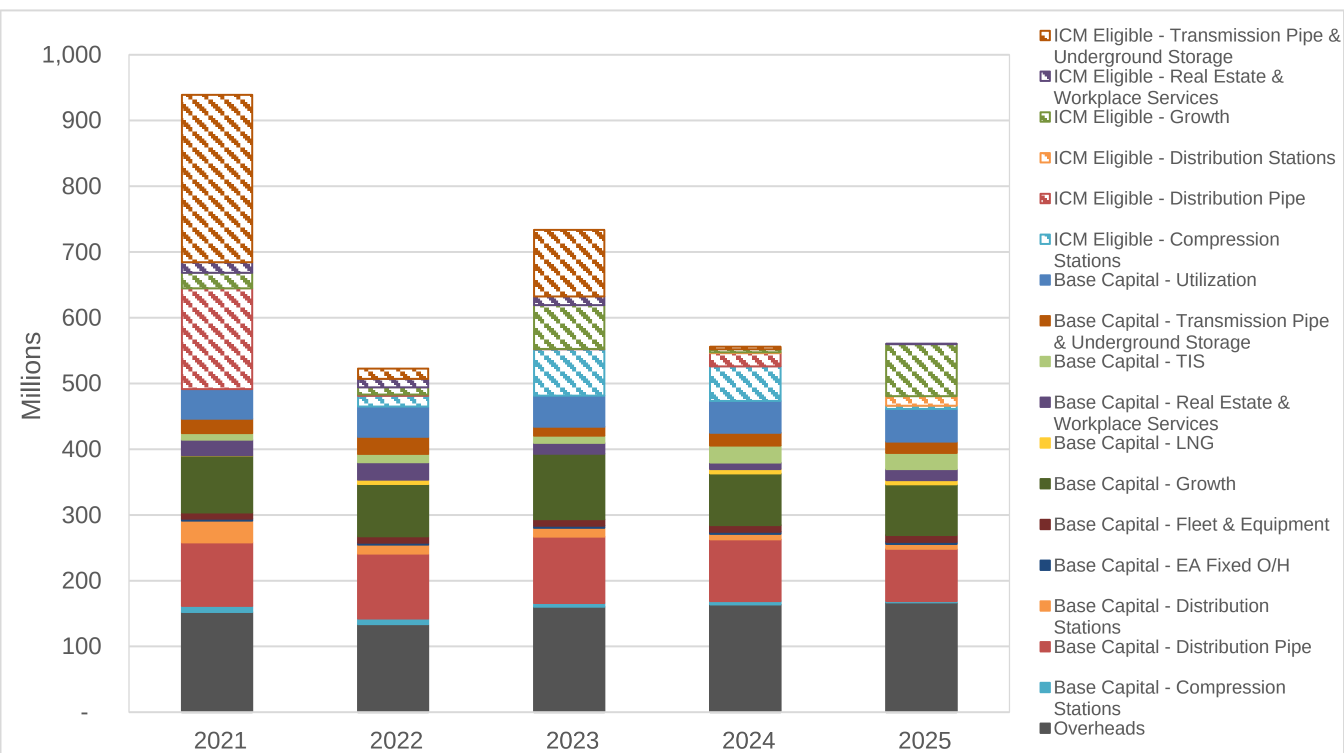

Figure 6.1-2: Union Rate Zones Pre-Optimized Spend Profile (Capital Expenditure)

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Prior to optimization, investments were categorized into planning groups (**Table 6.1-2**) in the asset investment planning tool, C55, based on asset management principles; this supported optimization activities where different treatment (fixed or variable timing) could be applied to the investment groups at the time of optimization. A majority of investments (85%) have fixed timing while approximately 15% have variable timing.

Table 6.1-2: Planning Groups

Planning Group	Description	Optimization Treatment
Base Capital - Compliance	Investment compliance requirements validated	Fixed timing
Base Capital – Mandatory	Investment mandatory requirements validated	Fixed timing
Base Capital - Executing	Executing investment to continue with previously approved timing	Fixed timing
Base Capital – Executing Flagged for Re-Optimization	Executing investment that could potentially have the remainder of the work shifted in timing	Timing optimized based on value
Base Capital – Risk Based	Value framework completed on the investment and not compliance, mandatory nor executing	Timing optimized based on value
Overheads	Overheads	Fixed timing
Incremental Capital Eligible – Risk Based	Investment meets ICM criteria. Value framework completed on the investment and not compliance, mandatory nor executing	Timing optimized based on value
Incremental Capital Eligible – Non-Risk Based	Investment meets ICM criteria. Compliance/ mandatory requirements validated or executing.	Fixed timing

Running C55 optimization at the defined capital constraint for each rate zone, an optimized solution could not be obtained. This was due to the level of fixed and mandatory projects.

To resolve this, a review of all investments that met the incremental capital requirements was completed. ICM-eligible investments that were likely to be causing the optimization runs to fail were removed from optimization, providing EGI with the best understanding of an optimized typical base spend profile. These investments were brought back into the plan after optimization was rerun. The objective was to consider as many investments within base capital before pursuing incremental capital treatment.

The optimized result and ICM-eligible projects were reviewed with all asset managers and business stakeholders. Proposed adjustments were driven by resource capacity, re-alignment with life cycle management strategies and where possible, maintaining a total spend within the capital constraint. Resource implications were also considered for routine maintenance activities to ensure that project pace and timing met life cycle strategies, adequately reduced risk and identified as feasible. Given the challenges faced in 2020, once COVID-related impacts to 2020 were starting to be identified, adjustments were made to reflect the impact on timing and cost of specific investments. Updates for any ICM-eligible projects were also reviewed and adjusted. Adjustments were incorporated as necessary through consultation with asset managers and using the value framework for project comparison.

Figure 6.1-3 and **Figure 6.1-4** present the five-year capital requirements by asset class, with five years of historical spend. For the EGD rate zone, the capital requirements to meet asset class objectives and life cycle management strategies, while managing risk, exceed the capital available for optimization in most years. For the Union rate zones, the capital requirements exceed the capital available for optimization in all years. The capital that exceeds the capital available for optimization can be considered as ICM-eligible capital per the definition in **Table 6.1-1**. The final five-year portfolio of spend was reviewed and approved by the Vice President of Engineering and the Asset Management Steering Committee.

Note: The total forecasted capital expenditures categorized by asset class depicted in **Figure 6.1-3** and **Figure 6.1-4** are comprised of each investment's direct costs and the associated overheads. Asset class historical spend profiles do not include associated overheads; for this reason, overheads are identified as a separate category historically.

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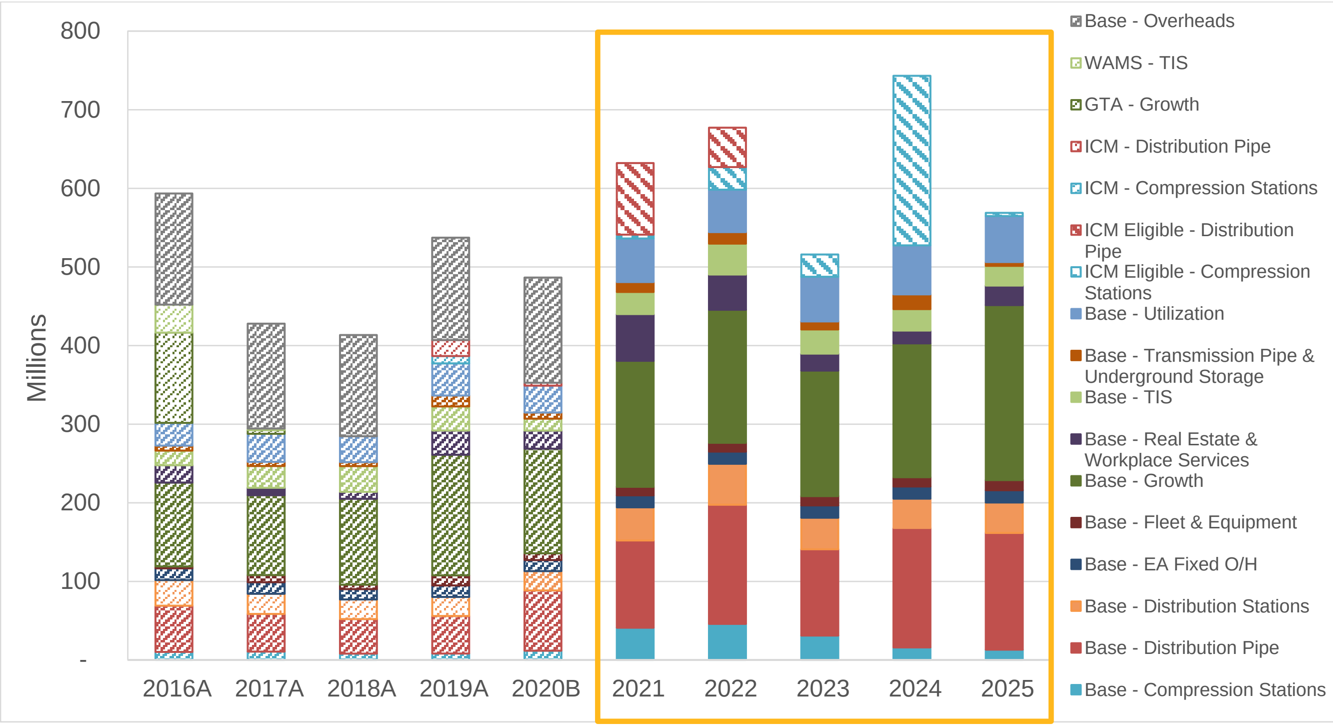

Figure 6.1-3: Final Five Year Plan by Asset Class (with ICM) – EGD Rate Zone (Capital Expenditure)

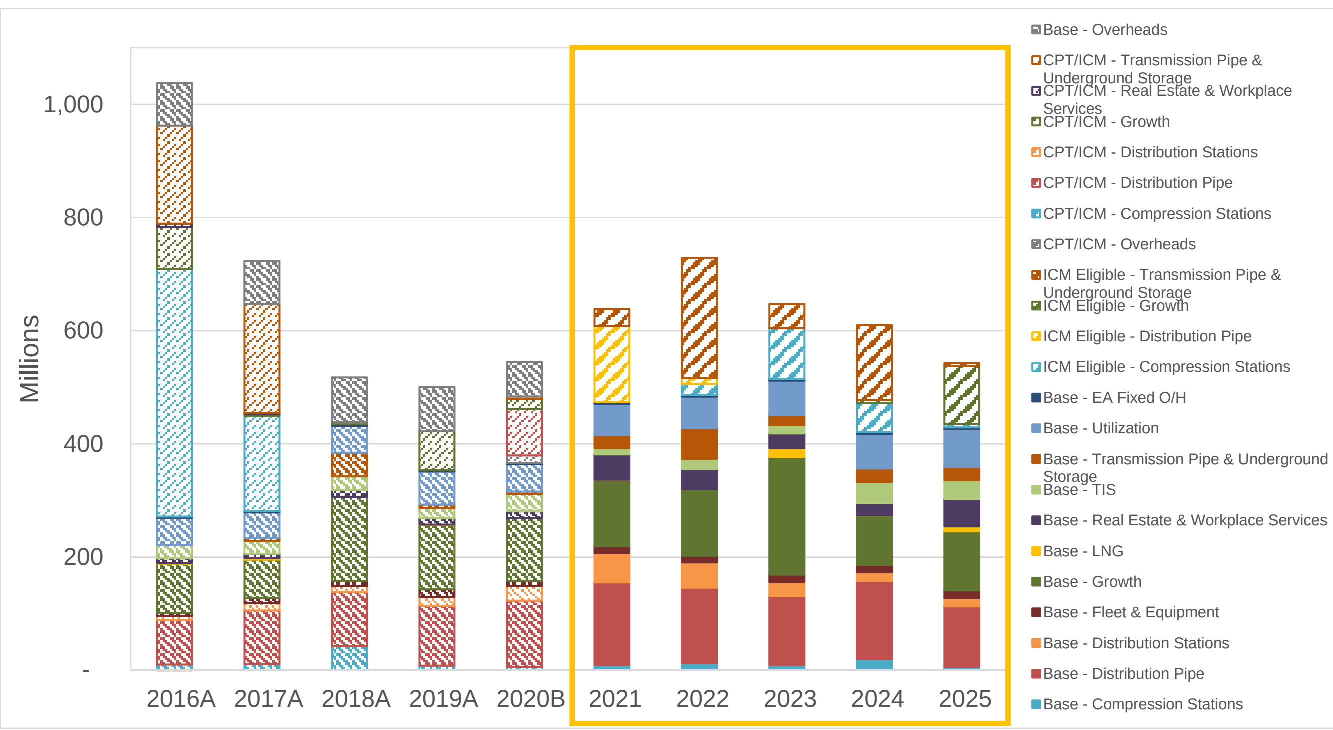

Figure 6.1-4: Final Five Year Plan by Asset Class (with ICM) – Union Rate Zone (Capital Expenditure)

Note: Historical actuals include both Capital Pass Through (CPT) Mechanism / Incremental Capital Module (ICM) projects. Forecast legend references ICM-eligible projects.

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Table 6.1-3 and **Table 6.1-4** list the ICM-eligible capital projects for the EGD and Union rate zones respectively. Investment costs do not include overheads.

Table 6.1-3: ICM-Eligible Capital Projects – EGD Rate Zone

Asset Class	Project Name	In-Service Year	2021-2025 Net Capital ($M)	Total Net Capital ($M)	Driver
Distribution Growth	Rideau Reinforcement	2025	52.7	53.5	Mandatory: Reinforcement Specified per Network Analysis
	York Region Reinforcement	2026	25.9	65.8	Mandatory: Reinforcement Specified per Network Analysis
	Amaranth System Reinforcement	2024	10.3	10.3	Mandatory: Reinforcement Specified per Network Analysis
	Thornton Reinforcement	2023	10.9	10.9	Mandatory: Reinforcement Specified per Network Analysis
Distribution Pipe	NPS 20 Lake Shore Replacement (Cherry to Bathurst)	2022	103.4	104.7	Condition
	St. Laurent Phase 3[13] St. Laurent Plastic - Montreal to Rockcliffe St. Laurent Plastic - Coventry/Cummings/St Laurent St. Laurent Plastic - Lower Section	2021	12.4	12.4	Condition
	NPS 12 St. Laurent Aviation Pkwy[13]	2022	29.5	29.8	Condition
	NPS 12 St. Laurent Queen Mary/Prince Albert[13]	2022	11.0	11.1	Condition
	NPS 12 Martin Grove Rd Main Replacement: Lavington to St. Albans Road	2024	18.3	18.3	Condition
	NPS 10 Glenridge Avenue, St. Catharines	2025	11.8	11.8	Condition
Distribution Stations	Harmer District Station	2022	13.1	13.1	Compliance and ILI requirements
Compression Stations	SCOR: K701/2/3 Reliability - Replacement	2024	185.2	185.2	Obsolescence
	Dehydration Expansion	2023	41.0	41.0	Condition; Growth

[13] *The St. Laurent portfolio of work consists of four phases of work and each phase is comprised of separate projects. Phases 1 & 2 have been previously completed, with Phases 3 & 4 remaining in this forecast period. Phase 3 includes the following investments: Three PE main investments in 2021 including Lower Section, Coventry/Cummings/St Laurent and Montreal to Rockcliffe. Phase 4 includes the following investments: NPS 12 St. Laurent Aviation Pkwy and NPS 12 St. Laurent Queen Mary/Prince Albert in 2022. The investments comprising Phases 3 & 4 will be combined in a single Leave to Construct application that will be submitted in Fall 2020.*

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Asset Class	Project Name	In-Service Year	2021-2025 Net Capital ($M)	Total Net Capital ($M)	Driver
	SCOR: Meter Area-Upgrade	Ph 1 - 2021 Ph 2 - 2022	34.2	45.5	Condition
	Storage Crowland (SCRW): Station-Renewal In-Place	2025	27.9	27.9	Obsolescence
Transmission Pipe and Storage	Crowland Pool (PCRW): Wells-Upgrade	2026	1.7	11.7	Compliance, Condition
REWS	Kennedy Road Expansion	2023	15.0	26.3	Condition
	Station B New Building	2021	15.5	17.6	Condition, Function, In Progress
	SMOC/Coventry Facility Consolidation	2023	30.8	30.8	Function and Service Coverage Duplication
	Kelfield Operations Centre	2023	10.8	10.8	Condition, Function
	VPC Core and Shell	2025	20.0	20.0	Condition

Note: Dismantlement costs are not included in Total In-Service Capital.

Table 6.1-4: ICM-Eligible Capital Projects – Union Rate Zones

Asset Class	Project Name	In-Service Year	2021-2025 Net Capital ($M)	Total Net Capital ($M)	Driver
Distribution Growth	Customer Stratford Reinforcement	2022	13.3	13.3	Mandatory: Reinforcement Specified per Network Analysis
	Dunnville Line Reinforcement (6.3 km of NPS 10)	2022	9.1	9.1	Mandatory: Reinforcement Specified per Network Analysis
	NBAY: Parry Sound Lateral Reinforcement (12.5 km of NPS 6)	2023	15.0	15.0	Mandatory: Reinforcement Specified per Network Analysis
	WATE: Owen Sound Transmission System, Reinforcement (28.8 km of NPS 16)	2025	81.7	83.6	Mandatory: Reinforcement Specified per Network Analysis
	LOND: Goderich Transmission System, Reinforcement (11.4 km of NPS 10)	2026	2.2	25.0	Mandatory: Reinforcement Specified per Network Analysis
	Ingersoll Transmission Station Rebuild	2022	8.4	8.4	Mandatory: Reinforcement Specified per Network Analysis

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Asset Class	Project Name	In-Service Year	2021-2025 Net Capital ($M)	Total Net Capital ($M)	Driver
	SUDB: Marten River Compression Reinforcement	2023	51.6	51.6	Mandatory: Reinforcement Specified per Network Analysis
Distribution Pipe	NPS 8 Port Stanley Replacement	2024	20.6	20.6	Condition
	INTE: North Shore - Section A: Retrofit ECDA to ILI	2021	12.0	12.3	Mandatory: Retrofit for TIMP program (ILI Compliance)
	LOND - London Lines Replacement	2021	106.2	110.3	Condition
	Kirkland Lake Lateral Replacement	2022	16.8	16.8	Condition
Compression Stations	Dawn Plant-C Compression Life Cycle	2024	131	131	Obsolescence
	Waubuno Compression Life Cycle	2024	12.9	12.49	Obsolescence
Transmission Pipe and Storage	Panhandle Line Replacement	2023	29.8	29.8	Condition, High Consequence
	INTE: Dawn - Cuthbert - ECDA to ILI Retrofit NPS 42, 34, 26	2022	24.6	25.0	Mandatory: Retrofit for TIMP program (ILI Compliance)
	Dawn Parkway Expansion (Kirkwall-Hamilton NPS 48)	2022	176.1	181.7	Growth
	Sarnia Expansion (NPS 20 Dow to Bluewater)	2021	19.2	20.5	Growth
	Sarnia Expansion (Novacor Station)		6.5	6.5	
	Sarnia Expansion - Bluewater Energy Park (Asset #1)	2024	64.5	64.6	Growth
	Sarnia Expansion Project- Bluewater Energy Park (Customer Station)		11.7	11.7	
	Sarnia Expansion - Bluewater Energy Park (Asset #2)		34.0	34	
REWS	Thunder Bay Regional Operations Centre	2025	10.2	10.2	Condition
	New Site No. 4	2023	28.8	28.8	Operations Site Consolidation

Note: Dismantlement costs are not included in Total In-Service Capital.

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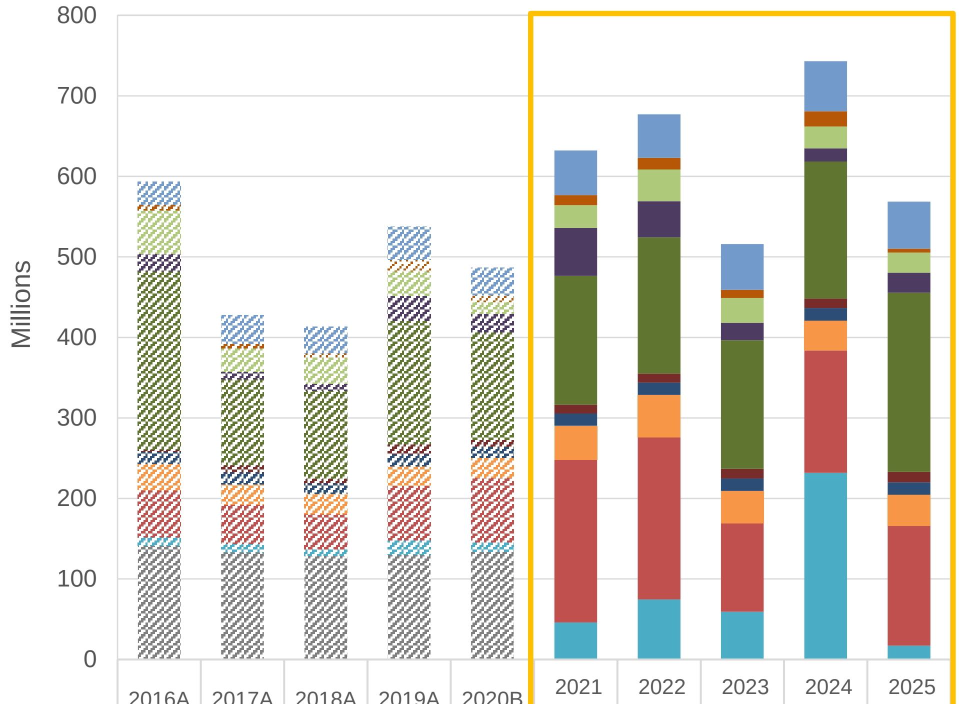
6.2 Summary of Capital Expenditure

Figure 6.2-1 and **Figure 6.2-2** present the direct five-year capital profile for EGI from 2021-2025, totaling over $3.1B and $3.2B in proposed asset expenditures for the EGD and Union rate zones respectively.



	2016A	2017A	2018A	2019A	2020B	2021	2022	2023	2024	2025
Utilization	28.9	35.7	32.9	40.9	34.3	55.3	54.1	56.8	62.3	58.5
Transmission Pipe & Underground Storage	6.4	5.3	5.1	13.9	7.8	12.5	14.5	10.1	18.7	4.8
TIS	54.3	29.6	32.8	30.6	15.1	28.2	39.4	30.8	27.3	25.1
Real Estate & Workplace Services	22.1	9.4	8.8	30.9	23.1	59.6	44.9	21.6	16.3	24.8
Growth	221.5	106.5	109.2	153.4	133.1	160.1	169.3	159.8	170.3	222.6
Fleet & Equipment	2.3	9.1	5.7	12.9	8.6	10.9	11.1	11.8	11.8	12.8
EA Fixed O/H	15.1	14.7	13.2	14.6	14.0	15.4	15.4	15.5	15.6	15.7
Distribution Stations	32.5	25.7	24.9	24.2	24.6	42.1	52.2	40.2	37.2	38.7
Distribution Pipe	58.8	47.9	43.9	68.0	80.3	202.0	201.7	109.9	151.9	148.6
Compression Stations	10.3	10.7	8.1	17.6	11.8	46.1	74.7	59.3	231.8	17.2
Overheads	141.4	133.3	128.6	130.2	133.8					

Figure 6.2-1: EGI Five-year Capital Profile by Asset Class (2021-2025) – EGD Rate Zone

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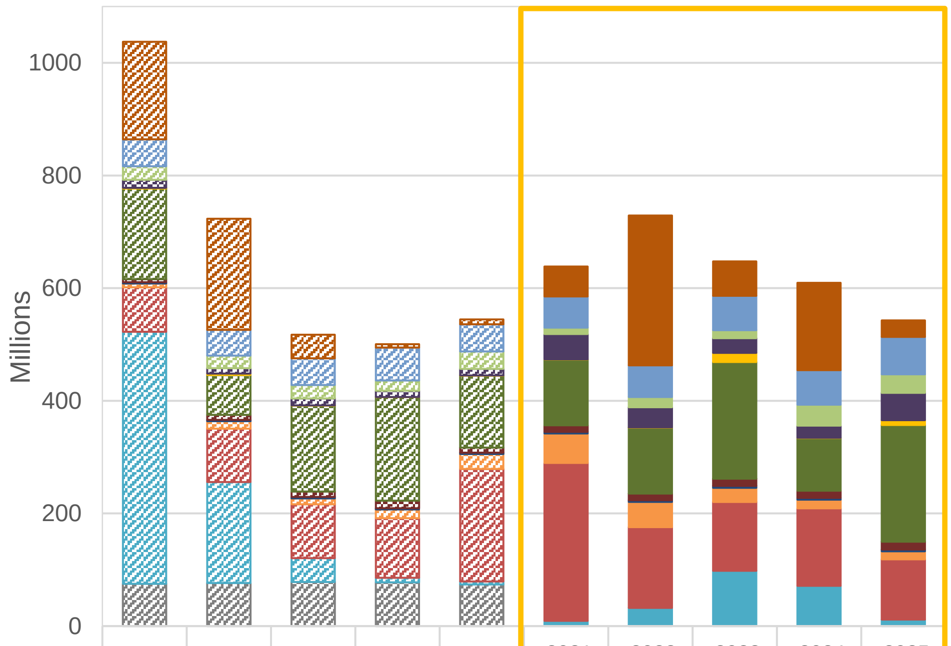
Figure 6.2-2: Five-year Capital Profile by Asset Class (2021-2025) – Union Rate Zones



	2016A	2017A	2018A	2019A	2020B	2021	2022	2023	2024	2025
Transmission Pipe & Underground Storage	173.1	197.2	41.9	5.9	8.6	53.1	266.0	61.1	155.2	29.3
Utilization	47.8	45.7	47.4	58.4	48.2	55.2	56.2	61.0	61.1	66.4
TIS	24.0	22.4	23.8	18.2	31.0	11.3	18.2	14.2	37.4	32.9
Real Estate & Workplace Services	14.4	9.5	12.4	11.2	11.7	44.9	35.7	26.3	21.5	48.6
LNG	1.1	2.4	0.1	0.0	0.3	0.3	0.2	16.0	0.2	8.7
Growth	161.0	70.9	152.8	184.0	127.9	116.9	117.2	207.4	93.6	207.0
Fleet & Equipment	5.4	8.9	9.6	13.4	8.9	11.7	12.0	12.8	12.8	13.9
EA Fixed O/H	2.2	2.3	2.6	2.1	2.4	2.8	3.0	3.1	3.2	3.3
Distribution Stations	6.9	13.3	10.4	15.5	26.6	52.3	44.7	25.2	15.5	14.3
Distribution Pipe	78.9	94.7	95.7	105.9	199.6	280.4	143.2	122.2	137.6	106.8
Compression Stations	447.4	179.4	42.3	8.1	5.3	9.3	32.5	98.2	71.4	11.7
Overheads	75.1	76.4	78.3	77.7	74.0					

Note: The total forecasted capital expenditures categorized by asset class depicted in **Figure 6.2-1** and **Figure 6.2-2** are comprised of each investment's direct costs and the associated overheads. Asset class historical spend profiles do not include associated overheads; for this reason, overheads are identified as a separate category historically.

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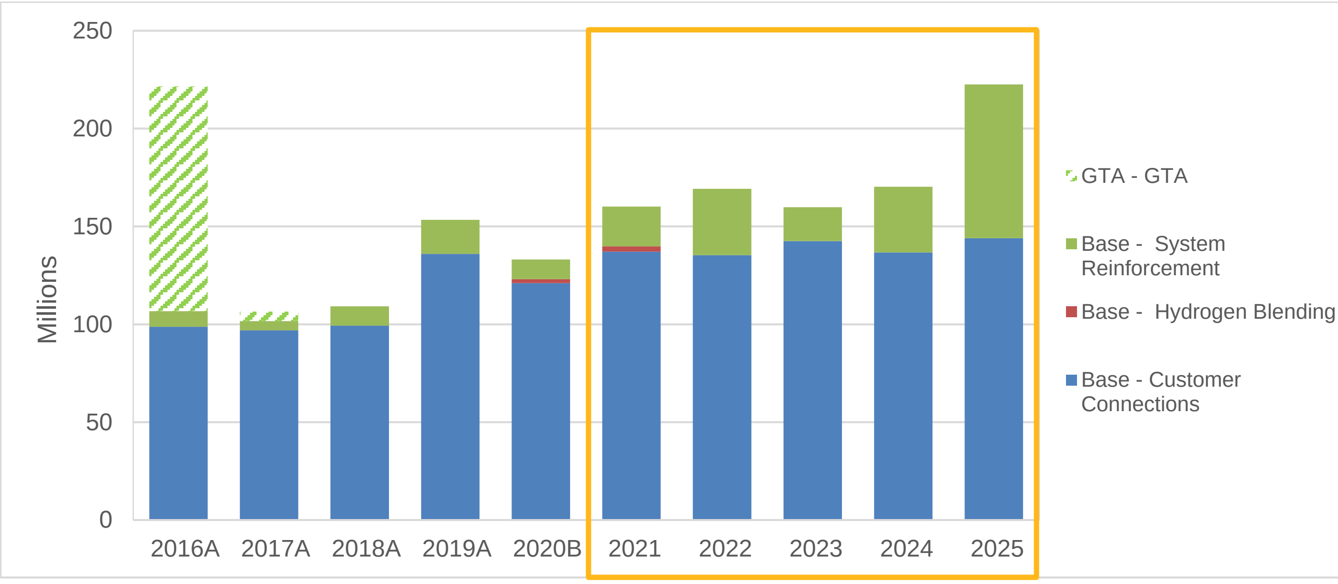
6.2.1 Growth

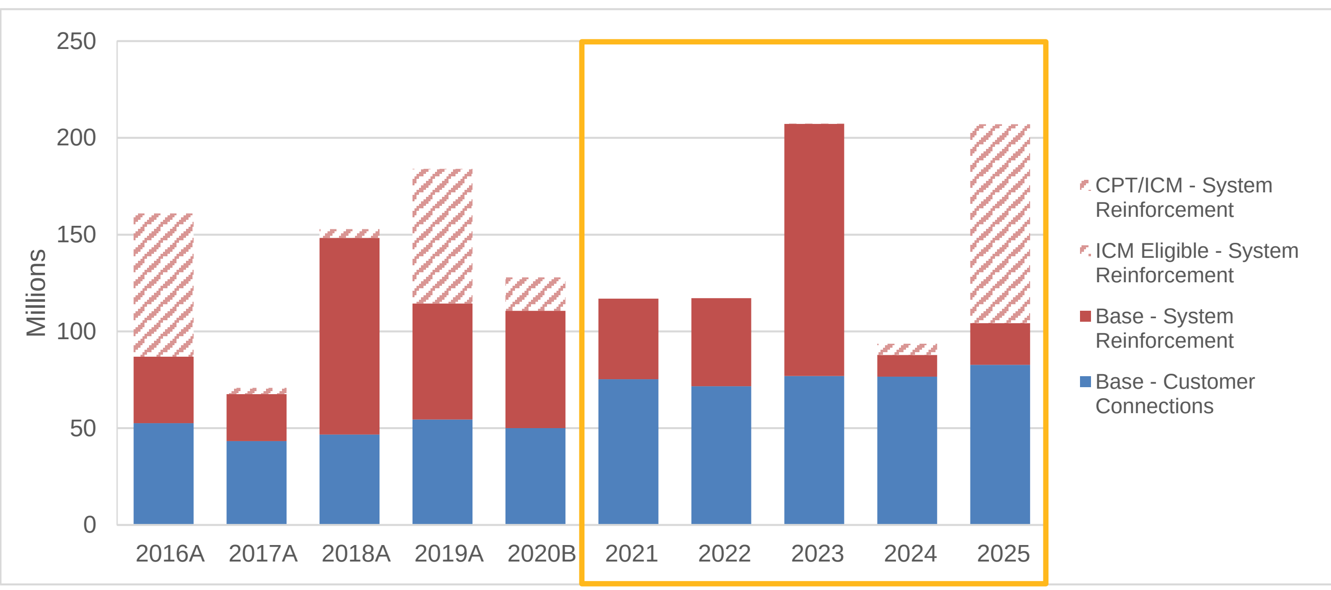
EGI has spent an average of $145M and $140M annually in the EGD and Union rate zones respectively for the Growth asset class. The total average capital spend is forecasted to be $163M (EGD RZ) and $148M (Union RZ) over the five years identified. The historical and projected five-year spend profiles are presented in **Figure 6.2-3** and **Figure 6.2-4**.



Note: Overheads excluded in historical spend.

Figure 6.2-3: Capital Expenditure over Time for Growth - EGD Rate Zone

The increase in capital requirements for the Growth asset class in 2025 in the EGD rate zone is primarily driven by reinforcement projects including Rideau Reinforcement and York Region Reinforcement project (2026 target in service).



Note: Overheads excluded in historical spend.

Figure 6.2-4: Capital Expenditure over Time for Growth - Union Rate Zones

The increase in capital requirements for the Growth asset class in the Union rate zones is primarily driven by the Sudbury Reinforcement project in 2023 and the Owen Sound Reinforcement project in 2025. The forecast also reflects increased costs per customer for customer connections based on actuals. Refer to **Section 5.1** for further details on the Growth asset class.

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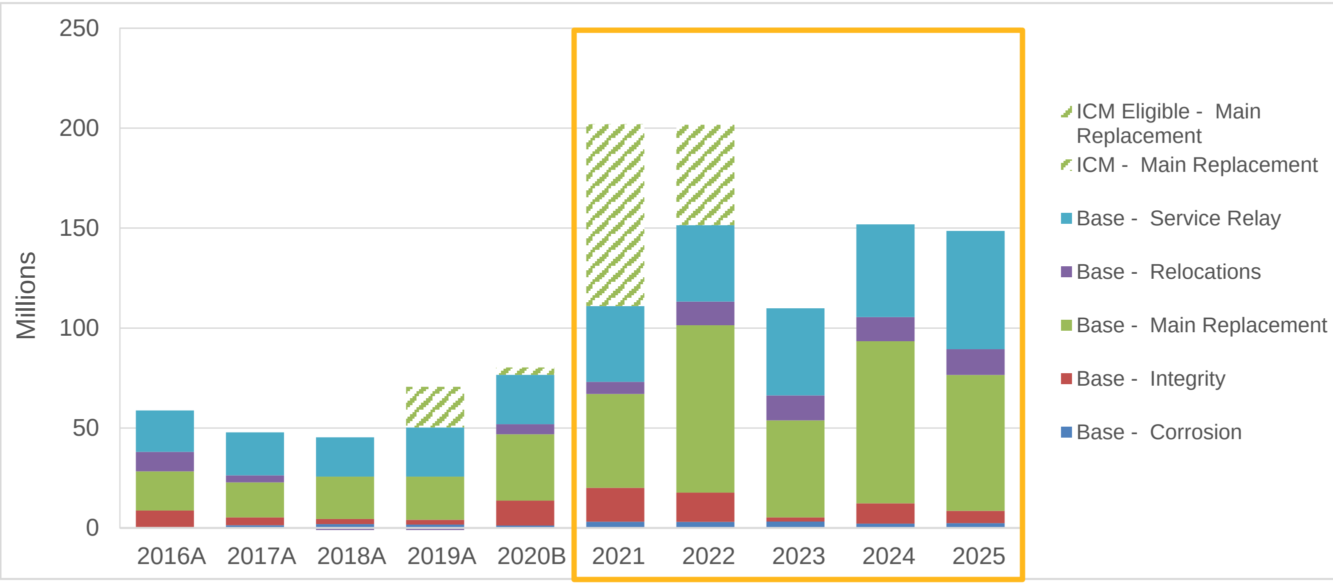
6.2.2 Distribution Pipe

EGI has spent an average of $60M and $115M annually in the EGD and Union rate zones respectively for the Distribution Pipe asset class. The total average capital spend is forecasted to be $161M (EGD RZ) and $157M (Union RZ) over the five years identified. The historical and projected five-year spend profiles are presented in **Figure** 6.2-5 and **Figure 6.2-6.**



Note: Overheads excluded in historical spend.

Figure 6.2-5: Capital Expenditure over Time for Distribution Pipe – EGD Rate Zone

The increase in capital requirements for the Distribution Pipe asset class in the EGD rate zone is primarily driven by an increased spend in the **Base – Main Replacement** portfolio in part due to increased proactive spend to renew vintage steel pipe. See **Section 5.2.4** and **Section 5.2.6.1.4** for the respective maintenance and replacement strategies for the Pipe asset class.

As a part of the Vintage Steel Mains Replacement program (see **Section 5.2.6.1.4**), EGI has identified large vintage steel main sub-systems that require renewal due to condition and risk.

Specific ICM-eligible projects include:

- NPS 20 Lake Shore Replacement (Cherry to Bathurst) (2022 In-service Date (ISD))
- St. Laurent Phase 3 (2021 ISD)
  - St. Laurent Plastic - Montreal to Rockcliffe
  - St. Laurent Plastic - Coventry/Cummings/St Laurent
  - St. Laurent Plastic - Lower Section
- NPS 12 St. Laurent Aviation Pkwy (2022 ISD)
- NPS 12 St. Laurent Queen Mary/Prince Albert (2022 ISD)
- NPS 12 Martin Grove Rd Main Replacement: Lavington to St. Albans Road (2024 ISD)
- NPS 10 Glenridge Avenue, St. Catharines (2025 ISD)

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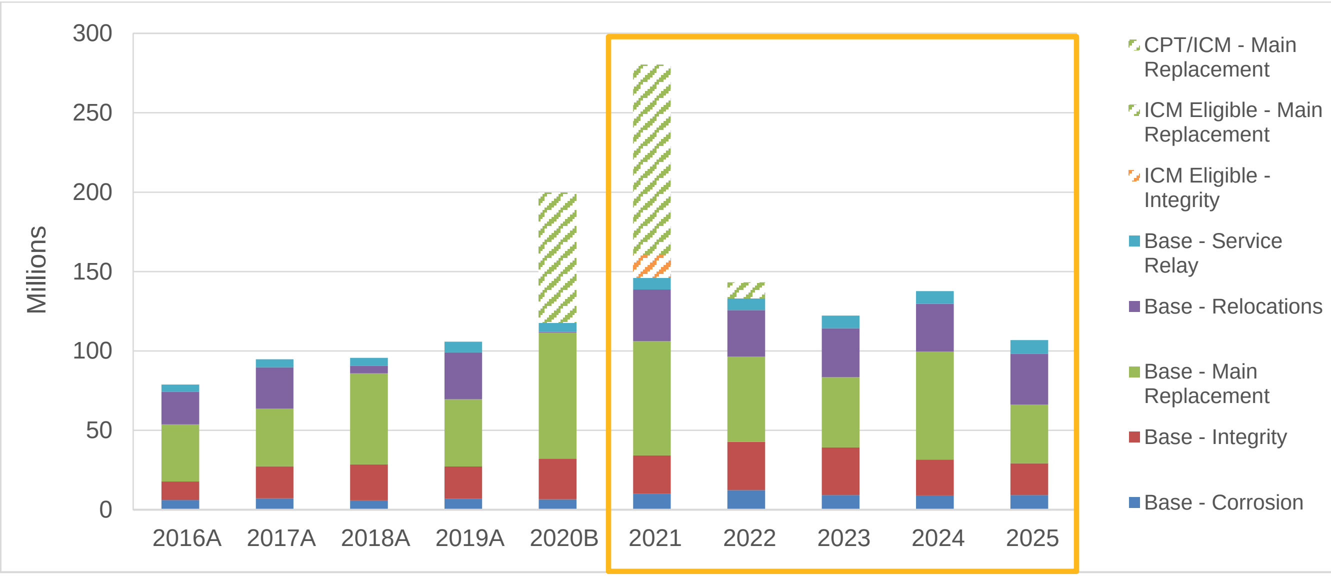


Note: Overheads excluded in historical spend.

Figure 6.2-6: Capital Expenditure over Time for Distribution Pipe – Union Rate Zones

The increase in capital requirements for the Distribution Pipe asset class in the Union rate zones is primarily driven by investments to complete the **Bare and Unprotected Steel Pipe Replacement** program (**Section 5.2.6.1.4**) by 2024 and replacement of large Vintage Steel Mains sub-systems that require renewal.

In all rate zones, Integrity capital has increased, reflecting EGI's Integrity Management program improvements which will require all pipelines operating at >30% SMYS to be retrofitted for in-line inspection. There is also expected to be an increase in the number of Integrity digs.

Specific ICM-eligible projects include:

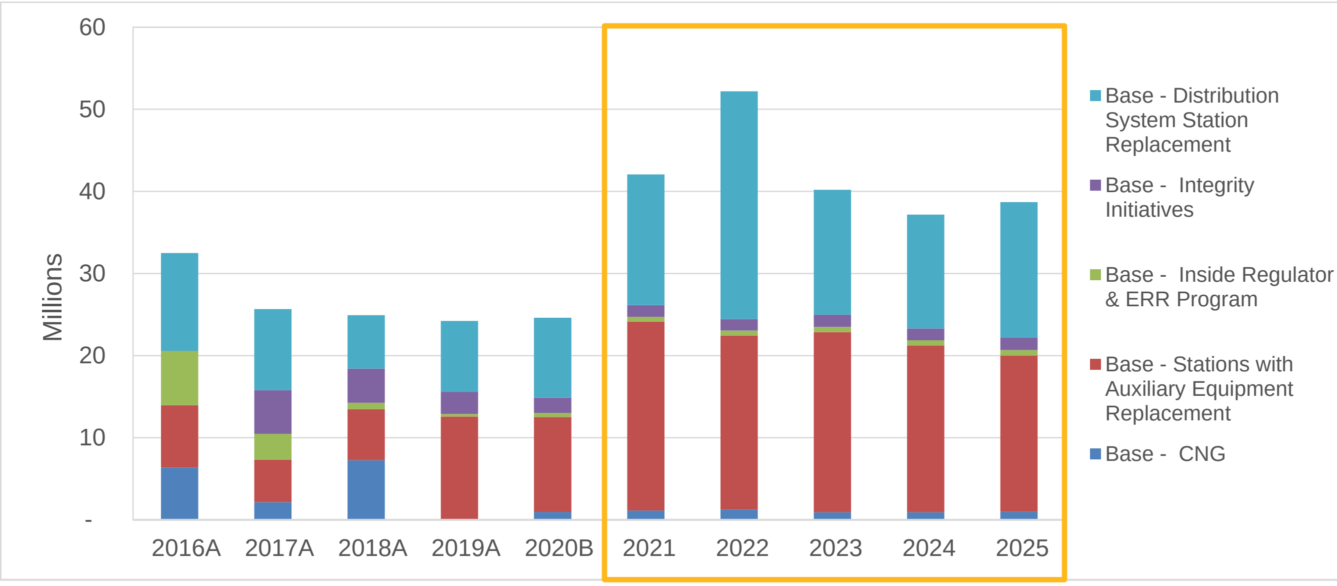
- London Lines Replacement (2021 ISD)
- NPS 8 Port Stanley Replacement (2024 ISD)
- INTE: North Shore - Section A: Retrofit ECDA to ILI (2021 ISD)
- Kirkland Lake Lateral Replacement (2022 ISD)

Refer to **Section 5.2** for further details on the Pipe asset class.

.

6.2.3 Distribution Stations

EGI has spent an average of $26M and $15M annually in the EGD and Union rate zones respectively for the Distribution Stations asset class. The total average capital spend is forecasted to be $41M (EGD RZ) and $31M (Union RZ) over the five years identified. The historical and projected five-year spend profiles are presented in **Figure 6.2-7** and **Figure 6.2-8**.



Note: Overheads excluded in historical spend.

Figure 6.2-7: Capital Expenditure over Time for Distribution Stations - EGD Rate Zone

The increase in capital requirements for the Distribution Stations asset class in the EGD rate zone is primarily driven by the strategies identified in **Section 5.3** (Distribution System Station Replacement and Stations with Auxiliary Equipment Replacement). The strategies aim to reduce risk, maintain a safe and reliable distribution system by the proactive replacement or the rebuild of station components prior to end-of-life.

The **Distribution System Station Replacement** portfolio has slight increases due to the strategies identified for the District, Header and Sales Stations programs. A large project in 2022 (Harmer District Station rebuild) skews the 2022 budget.

The **Stations with Auxiliary Equipment Replacement** portfolio has a similar quantity of projects as previous years, targeting larger stations and components for replacement in the next five years. Execution costs are higher in some areas due to complexities compared to preceding years, such as the inclusion of filtration that was previously not consistent across rate zones and pre-fabricated heating systems that standardize design.

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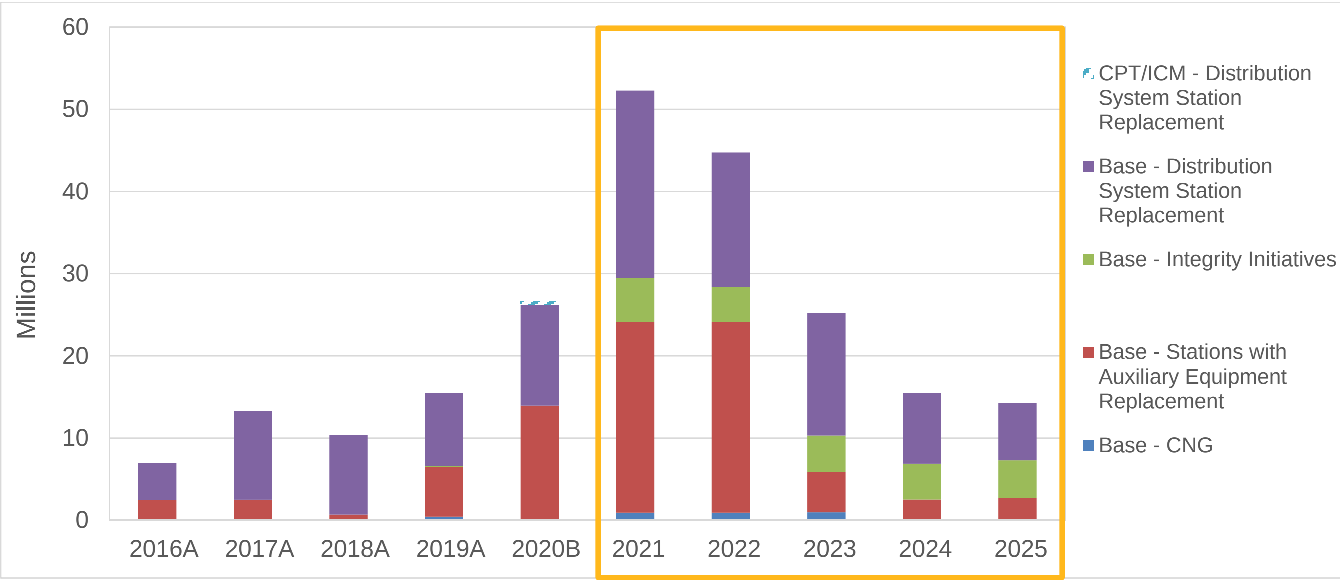


Note: Overheads excluded in historical spend.

Figure 6.2-8: Capital Expenditure over Time for Distribution Stations - Union Rate Zones

The increase in capital requirements for the Distribution Stations asset class in the Union rate zones is primarily driven by the inclusion of Odourant programs (previously in the Measurement asset class) and the inclusion of projects from the Growth asset class.

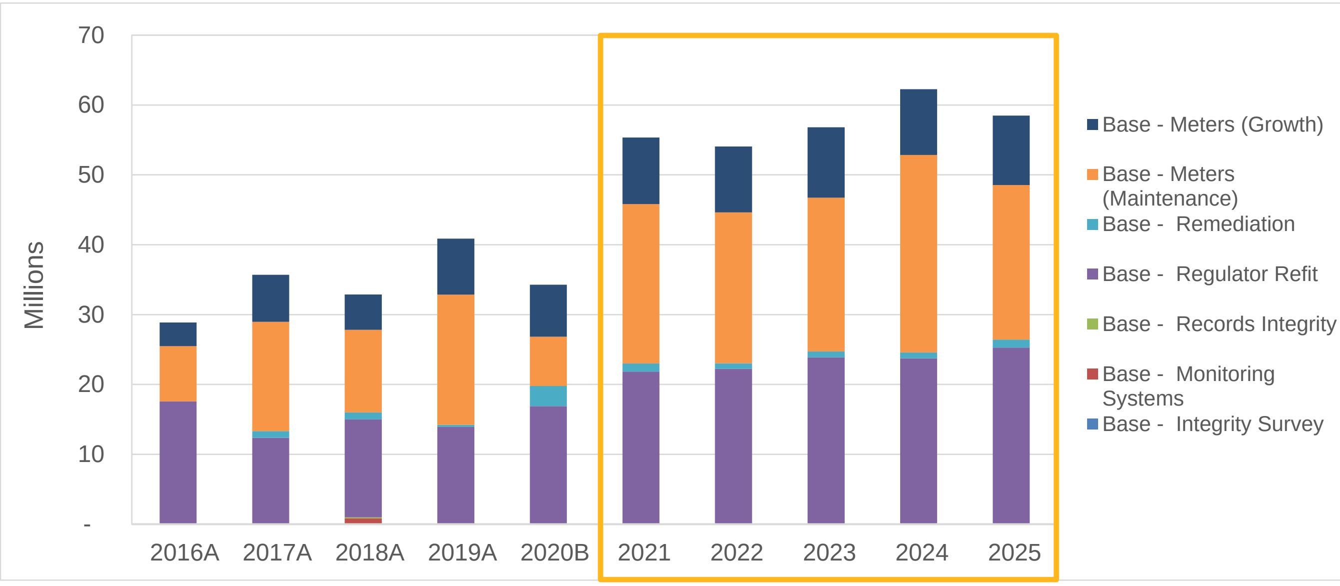
At the time of portfolio development, a number of the inputs to develop the proactive programs for this rate zone were in varying stages of maturity (such as FIMP and DIMP). Proactive programs are being developed and future year spend is expected to increase and will be supported with the requisite analysis that is underway.

Refer to **Section 5.3** for further details on the Distribution Stations asset class.

.

6.2.4 Utilization

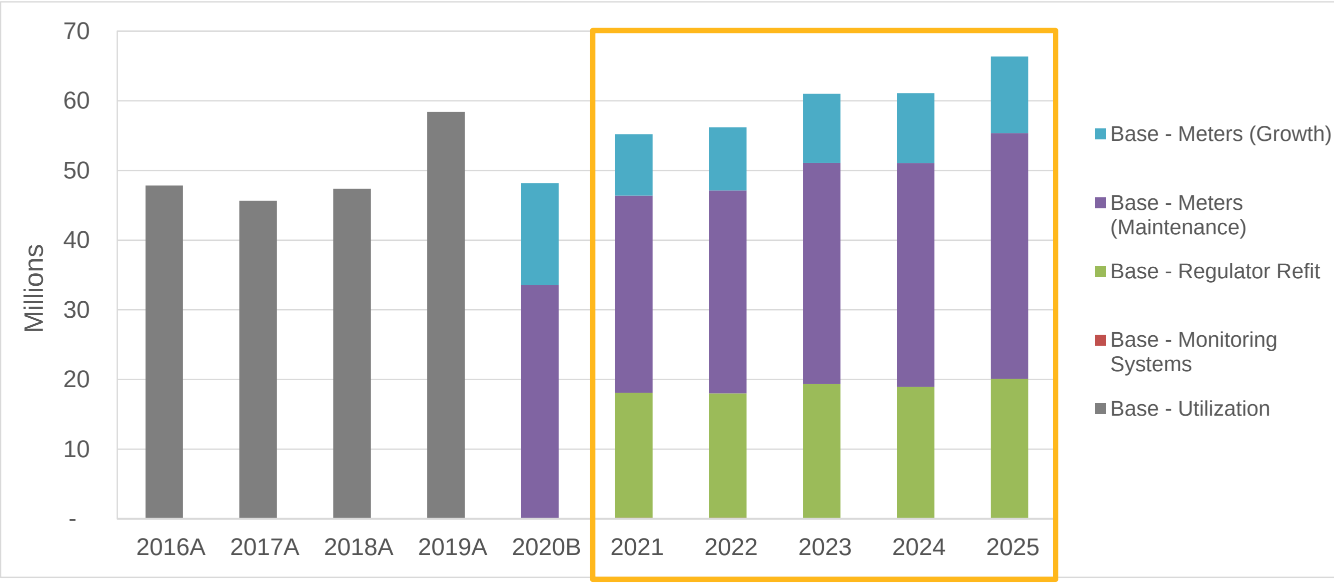
EGI has spent an average of $35M and $50M annually in the EGD and Union rate zones respectively for the Utilization asset class. The total average capital spend is forecasted to be $57M (EGD RZ) and $60M (Union RZ) over the five years identified. The historical and projected five-year spend profiles are presented in **Figure 6.2-9** and **Figure 6.2-10**.



Note: Overheads excluded in historical spend.

Figure 6.2-9: Capital Expenditure over Time for Utilization - EGD Rate Zone

The increase in capital requirements for the Utilization asset class in the EGD rate zone is primarily driven by a forecast increase in the number of meter replacements.



Note: Overheads excluded in historical spend.

Figure 6.2-10: Capital Expenditure over Time for Utilization - Union Rate Zones

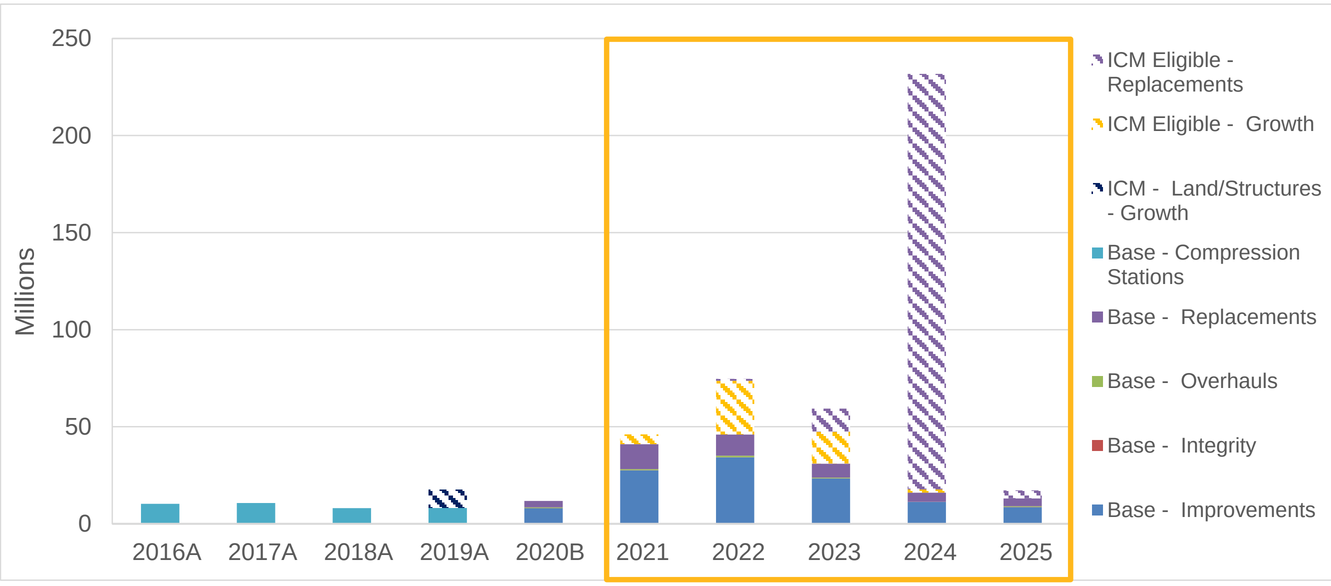
The forecast for the Utilization asset class in the Union rate zones is a steady trend of capital spend.

Refer to **Section 5.4** for further details on the Utilization asset class.

6.2.5 Compression Stations

EGI has spent an average of $12M and $137M annually in the EGD and Union rate zones respectively for the Compression Stations asset class. The total average capital spend is forecasted to be $86M (EGD RZ) and $45M (Union RZ) over the five years identified. The historical and projected five-year spend profiles are presented in **Figure 6.2-11** and **Figure 6.2-12.**

Note: The Compression Stations asset class includes Dehydration investments.



Note: Overheads excluded in historical spend.

Figure 6.2-11: Capital Expenditure over Time for Compression Stations - EGD Rate Zone

In addition to the large ICM-eligible projects listed below, the increase in capital requirements for the Compression Stations asset class in the EGD rate zone is primarily driven by valve replacements in the Corunna compressor station, compressor foundation block replacement (2022) and improvements to the power cylinder balancing system for the Corunna compressors.

Specific ICM-eligible projects include:

- SCOR: K701/2/3 Reliability – Replacement (2024 ISD)
- Dehydration Expansion (2023 ISD)
- SCOR: Meter Area Upgrade - Phase 1 (2021 ISD) and Phase 2 (2022 ISD)
- SCRW: Station Renewal In-Place (2025 ISD)

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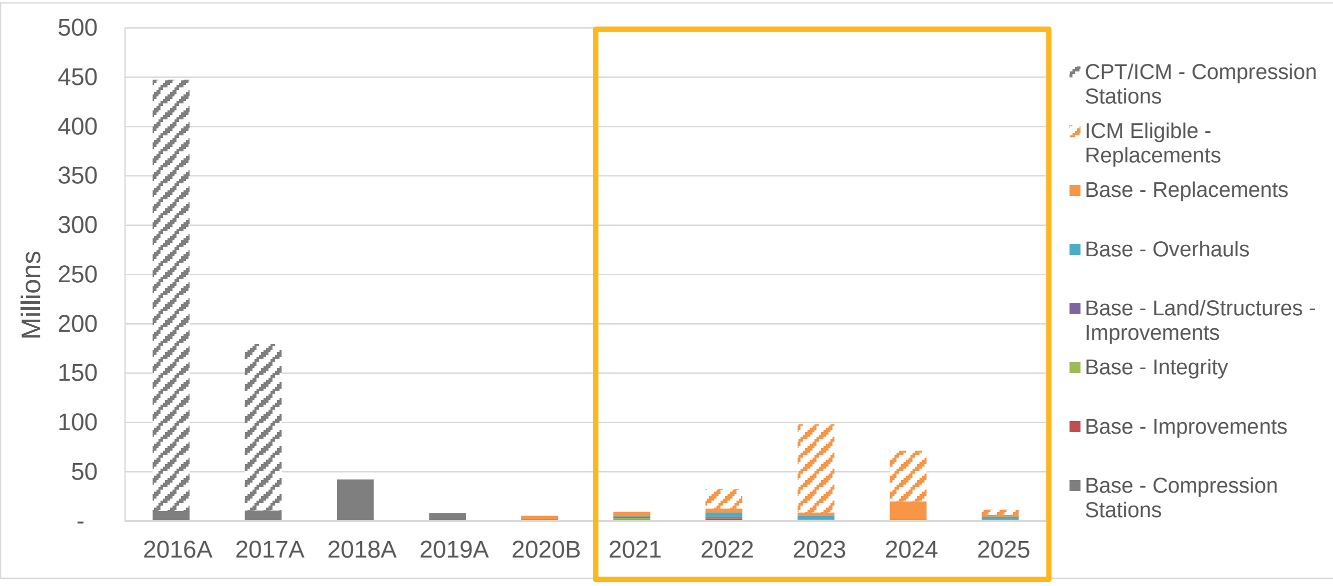

Note: Overheads excluded in historical spend.

Figure 6.2-12: Capital Expenditure over Time for Compression Stations - Union Rate Zones

The increase in capital requirements for the Compression Stations asset class in the Union rate zones is driven by compressor engine overhauls, replacement of the obsolete Waubuno compressor (ISD 2024) and replacement of the compressor control panels at the Hagar LNG station. The Dawn Plant-C Compression Life Cycle (a multi-year project spanning 2022-2025) accounts for majority of 2023 spend.

Refer to **Section 5.5.5** for further details on the Compression Stations asset class.

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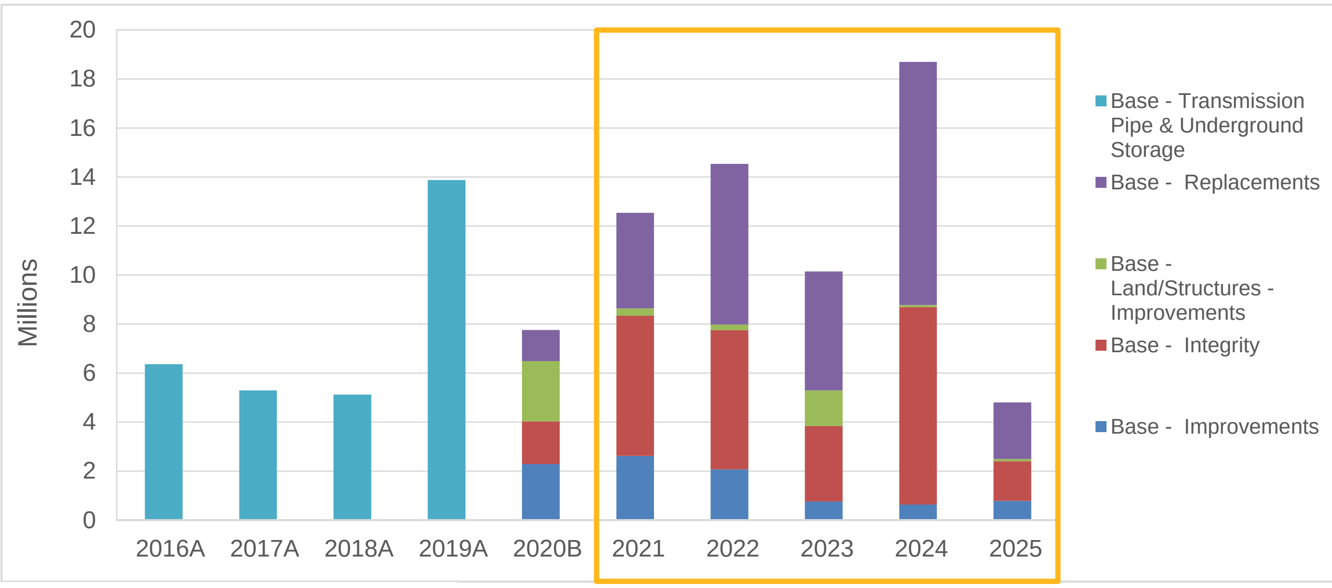
6.2.6 Transmission Pipe and Underground Storage

EGI has spent an average of $8M and $85M annually in the EGD and Union rate zones respectively for the Transmission Pipe and Underground Storage asset class. The total average capital spend is forecasted to be $12M (EGD RZ) and $112M (Union RZ) over the five years identified. The historical and projected five-year spend profiles are presented in **Figure 6.2-13** and **Figure 6.2-14.**

Note: The Transmission Pipe and Underground Storage class includes transmission reinforcement investments.



Note: Overheads excluded in historical spend.

Figure 6.2-13: Capital Expenditure over Time for Transmission Pipe and Underground Storage - EGD Rate Zone

The increase in capital requirements over the next five years is driven by the spend to install new storage wells, replacing lost storage deliverability due to well abandonments completed in the past five years.

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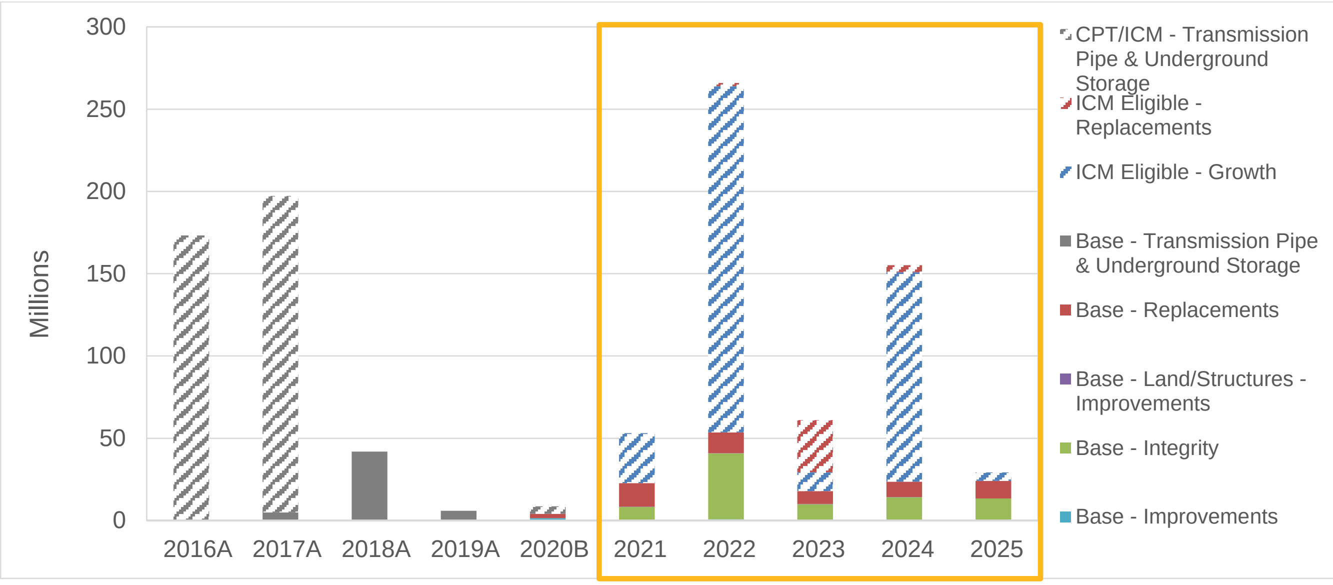


Note: Overheads excluded in historical spend.

Figure 6.2-14: Capital Expenditure over Time for Transmission Pipe and Underground Storage - Union Rate Zones

The Transmission Pipe and Underground Storage capital profile in the Union rate zones is largely made up of the Integrity Digs program and the Depth of Cover Mitigation program over the next five years.

Specific ICM-eligible projects include:

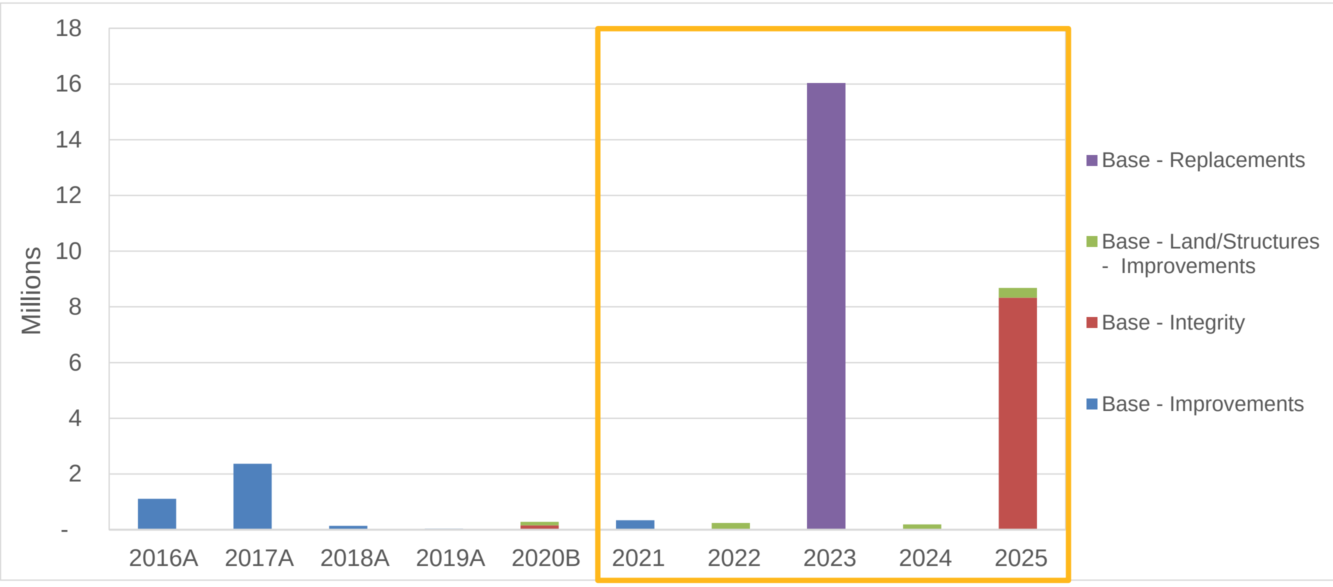
- Dawn Parkway Expansion (Kirkwall-Hamilton NPS 48) (2022 ISD)
- Sarnia Expansion - Bluewater Energy Park (2024 ISD)
- Panhandle Line Replacement (2023/2024 ISD)
- Sarnia Expansion - (2021 ISD)
- Dawn-Cuthbert (2022 ISD)

In both rate zones, Integrity capital has increased reflecting EGI's Integrity Management Program (IMP) improvements which will require all pipelines operating at >30% SMYS to be retrofitted for in-line inspection. There is also expected to be an increase in the number of Integrity digs.

Refer to **Section 5.5.7**and **Section 5.5.8** for further details on the Transmission Pipe and Underground Storage asset class.

6.2.7 Liquefied Natural Gas

EGI has spent an average of $0.8M annually in the Union rate zones for the Liquefied Natural Gas (LNG) asset class. The total average capital spend is forecasted to be $5M over the five years identified. The historical and projected five-year spend profile is presented in **Figure 6.2-15**.



Note: Overheads excluded in historical spend.

Figure 6.2-15: Capital Expenditure over Time for Liquefied Natural Gas - Union Rate Zones

The increase in capital requirements is driven by the replacement of critical assets in the LNG process due to obsolescence and condition. The significant investments identified are replacement of the boil-off gas compressor (2023), cycle gas compressor (2023) and the cold box (2025).

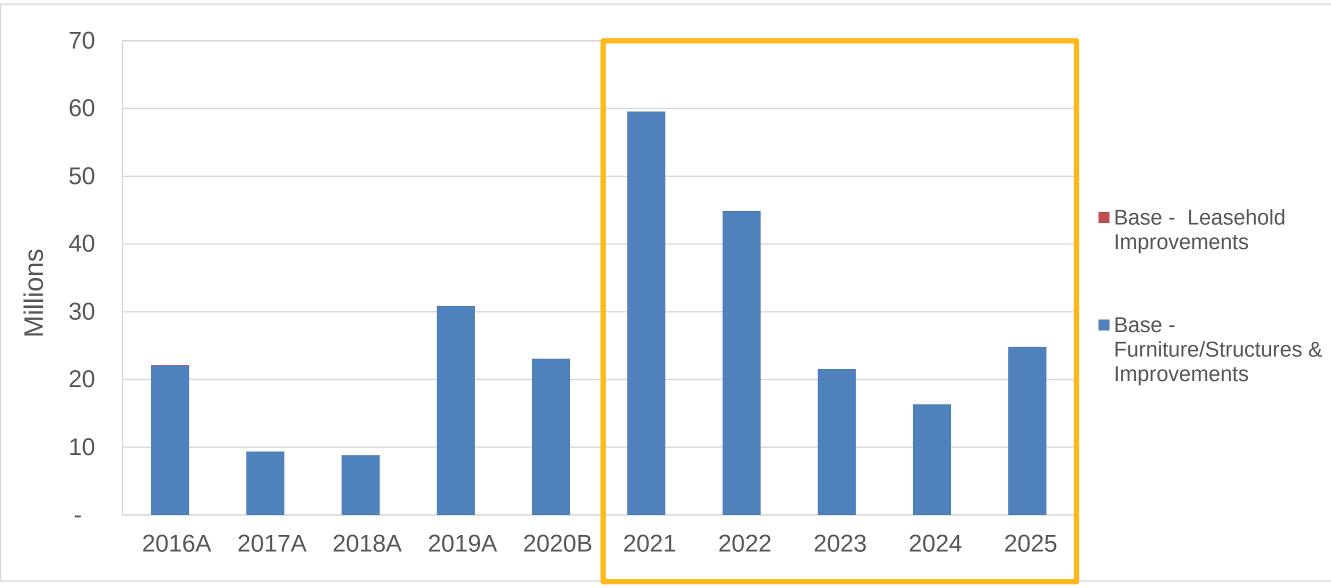
Note: LNG assets are in the Union North rate zone only.

Refer to **Section 5.5.9** for further details on the LNG asset class.

.

6.2.8 Real Estate and Workplace Services

EGI has spent an average of $19M and $12M annually in the EGD and Union rate zones respectively for the Real Estate and Workplace Services (REWS) asset class. The total average capital spend is forecasted to be $36M (EGD RZ) and $34M (Union RZ) over the five years identified. The historical and projected five-year spend profiles are presented in **Figure 6.2-16** and **Figure 6.2-17**.



Note: Overheads excluded in historical spend.

Figure 6.2-16: Capital Expenditure over Time for REWS - EGD Rate Zone

EGI continues to respond to the needs of its operations and growing customer needs, leveraging the facility assessment process to best determine whether existing facilities should be upgraded or replaced.

Specific ICM-eligible projects include for the EGD rate zone include:

- Kennedy Road Expansion (2024 ISD)
- Station B New Building (2021 ISD)
- SMOC/Coventry Facility Consolidation (2027 ISD)
- Kelfield Operations Centre Obsolescence (2023 ISD)
- VPC Core and Shell Obsolescence (2025 ISD)

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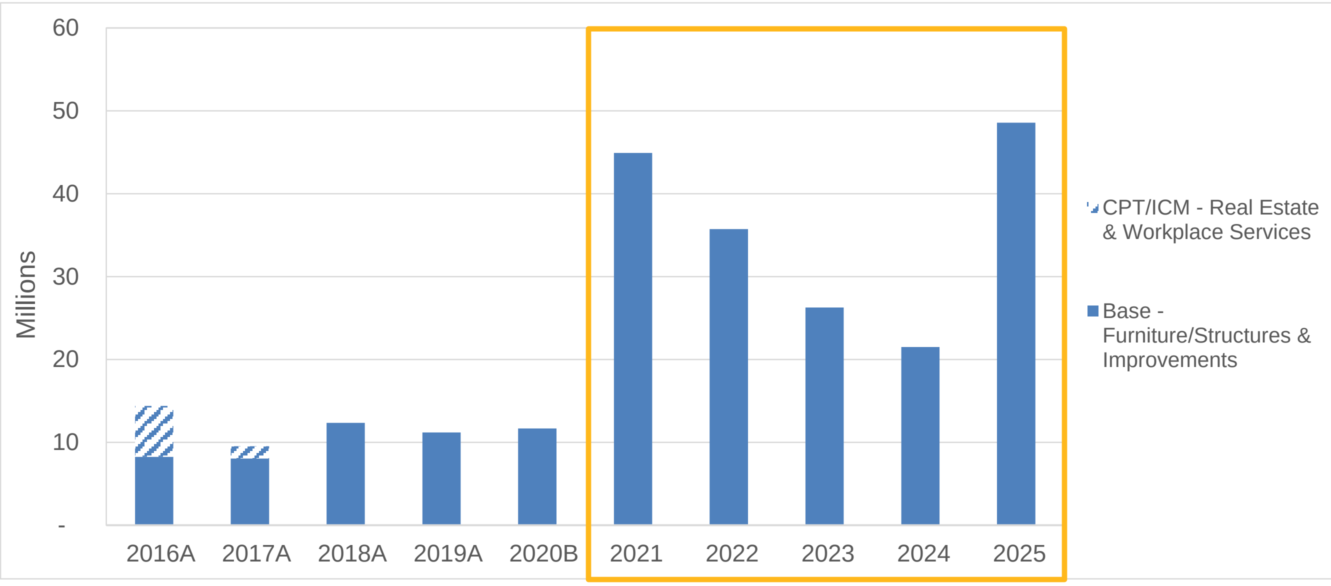


Note: Overheads excluded in historical spend.

Figure 6.2-17: Capital Expenditure over Time for REWS - Union Rate Zones

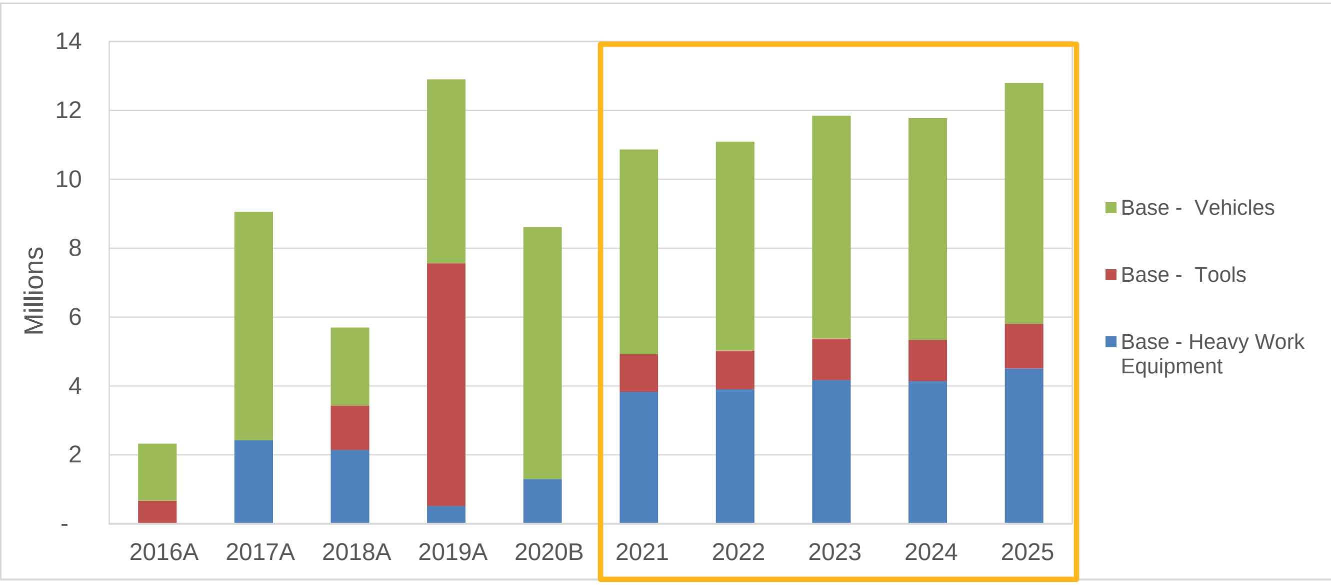
Projects for the Union rate zones include improvements to 50 Keil Drive and the Micro-Operations Sites program as well as specific ICM-eligible projects including:

- Thunder Bay Regional Operations Centre (2026 ISD)
- New Site No. 4 (2023 ISD)

Refer to **Section 5.6** for further details on the REWS asset class.

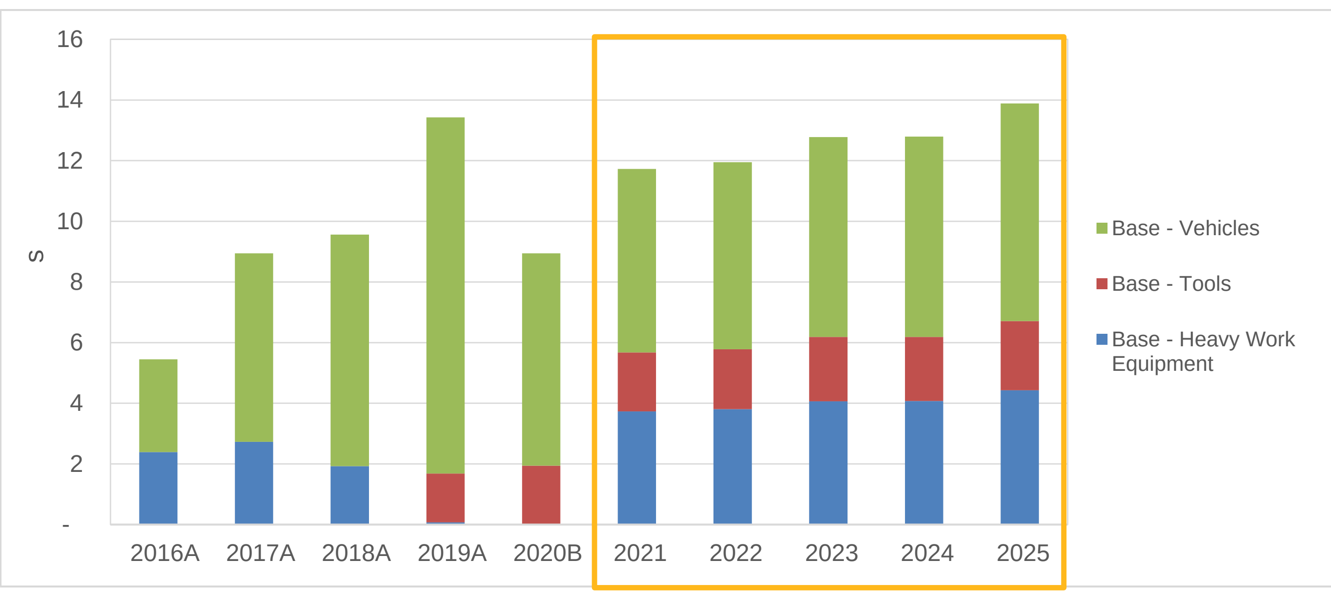
6.2.9 Fleet and Equipment

EGI has spent an average of $7M and $9M annually in the EGD and Union rate zones respectively for the Fleet and Equipment asset class. The total average capital spend is forecasted to be $11M (EGD RZ) and $12M (Union RZ) over the five years identified. The historical and projected five-year spend profiles are presented in **Figure 6.2-18** and **Figure 6.2-19**.



Note: Overheads excluded in historical spend.

Figure 6.2-18: Capital Expenditure over Time for Fleet and Equipment - EGD Rate Zone



Note: Overheads excluded in historical spend.

Figure 6.2-19: Capital Expenditure over Time for Fleet and Equipment - Union Rate Zones

For fleet investments in both rate zones, the forecast is a steady trend of capital to replace vehicles and equipment (based on fleet management strategy) to maintain the quality of the fleet.

Refer to **Section 5.7** for further details on the Fleet and Equipment asset class.

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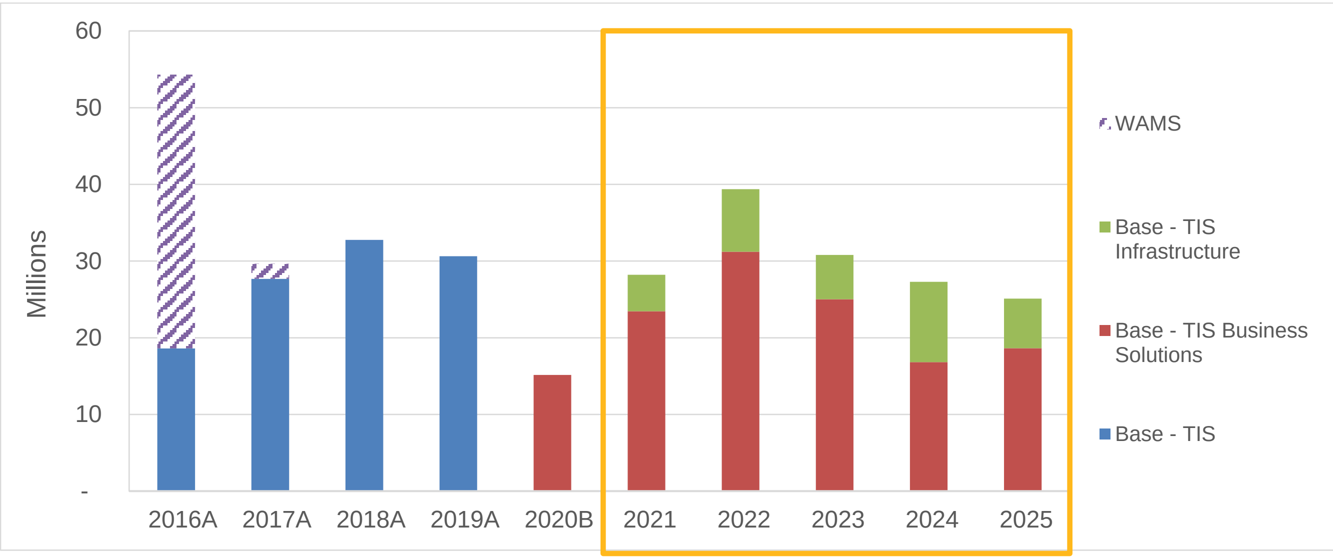
6.2.10 Technology and Information Services (TIS)

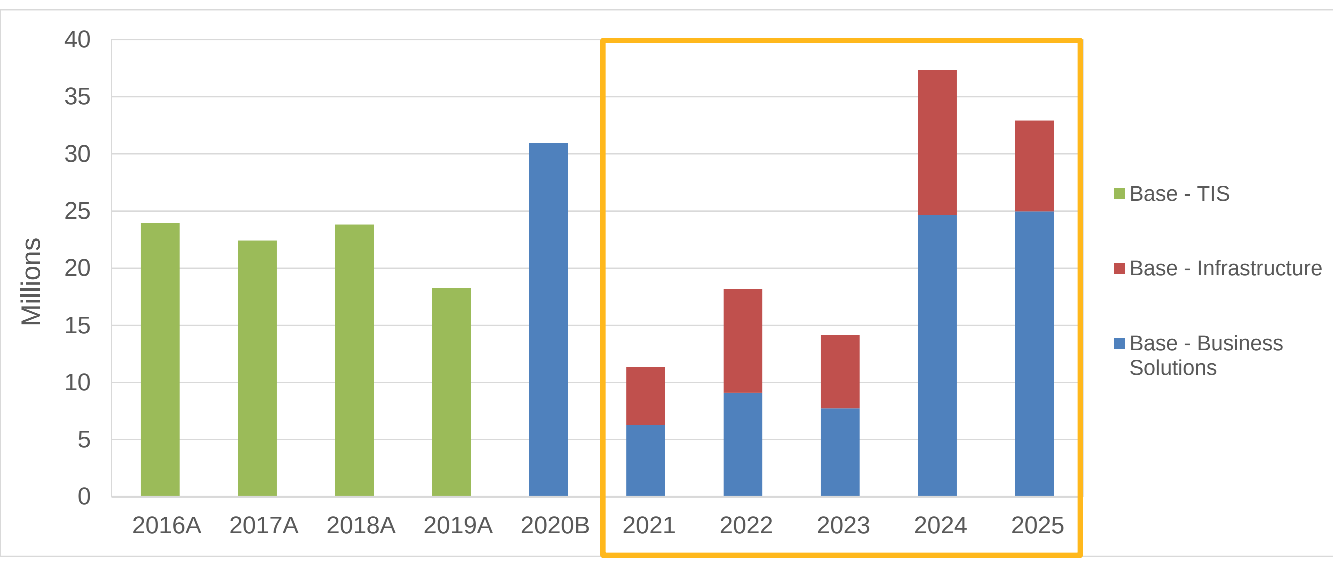
EGI has spent an average of $32M and $24M annually in the EGD and Union rate zones respectively for the Technology and Information Services (TIS) asset class. The total average capital spend is forecasted to be $30M (EGD RZ) and $22M (Union RZ) over the five years identified. The historical and projected five-year spend profiles are presented in **Figure 6.2-20** and **Figure 6.2-21**.



Note: Overheads excluded in historical spend.

Figure 6.2-20: Capital Expenditure over Time for TIS - EGD Rate Zone

Spend in 2020 has been lower as TIS has been concentrating on integration activities, which are not reflected in the core capital numbers. The increased forecast spend is driven by enhancements to already integrated applications and new business solutions for the utility are identified. Specifically, in 2022, the increase is reflective of a couple of large initiatives in the Customer Care space, building on the newly integrated CIS application.



Note: Overheads excluded in historical spend.

Figure 6.2-21: Capital Expenditure over Time for TIS – Union Rate Zones

TIS spending for the Union rate zones has decreased as TIS will be concentrating on integration activities, which are not reflected in core capital numbers. The increase in 2024 and 2025 reflects specific investment on a proposed major system replacement of the applications used in the Nominations solution. Refer to **Section 5.8** for further details on the TIS asset class.

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6.3 Assumptions

The five-year capital plan is based on the best available information at the time of completion. Key assumptions, as detailed in the tables below, provide a basis for interpretations.

Table 6.3-1: Assumptions for All Categories

Assumption	Basis for Assumption
Optimization results are based on available information as of April 2020.	Based on EGI's Portfolio Optimization process, the portfolio of spend is determined through the completion of C55 leveling and subsequent reviews. Results are based on best available information and COVID impacts have been incorporated where they are understood through these reviews.
Future costs are valued at 2020 Present Value.	Current practice forecasts projects based on 2020 rates. An annual inflation factor of 2.0% was applied to programs with defined scope/unit rates (such as meter purchases, customer growth and service relays).
All cost estimates are based on available information as of April 2020.	Using EGI's Value-Based Asset Management Model, these requirements will be reviewed and revised as required.
All Risk Assessments are based on risk models and methodology as of April 2020.	Using EGI's Value-Based Asset Management Model, the risk management framework will be reviewed and revised as required.
Projects in flight that span over multiple years must continue until complete.	Once a project is in progress it is inefficient and costly to terminate.
Historical actual costs are valued at years' actual value.	Historical values are not adjusted to be expressed in present value.

Table 6.3-2: Renewal Assumptions

Assumption	Basis for Assumption
Asset health provides a reasonable representation for asset condition and remaining asset life for forecasting purposes.	Reliability engineering is used to understand asset health. Based on projected life cycles, consequences of failure, tacit knowledge and asset data, risk is quantified. Renewal projects are planned to reduce this risk to the lowest practicable level.

Table 6.3-3: Customer Growth Assumptions

Assumption	Basis for Assumption
Customer growth is forecasted using historical trends and economic projections for the planning period.	The customer growth forecast considers new housing starts, meetings with builders and developers, municipal growth forecasts, general economic indicators and projections provided by specialized external consultants to combine localized trends with macro-economic factors.
Load forecasting is based on current understanding of temperature inputs and estimated customer consumptions.	EGI is cognizant that there may be impacts to customer growth forecasts based on climate/carbon policies. EGI currently has Demand Side Management (DSM) programs in place for our customers. Historical DSM is built into the load forecast based on past results. Should Integrated Resource Planning (IRP) drive more load reduction programming as a result of the IRP Policy Proposal (*EB-2020-0091*) and subsequent planning activity, impacts would be factored into future Asset Management Plans.

Table 6.3-4: Solution Planning Assumptions

Assumption	Basis for Assumption
Budgeting and forecast are determined through the solution planning process.	Estimates are determined considering region and work type to accurately forecast. Appropriate project planning processes are followed.

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7. Appendix

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EGI Asset Management Plan 2021-2025 Appendix

Growth

ENBRIDGE **Investment Summary Report**	Investment Code **19968**	Report Start Year **2021**	Number of Years **5**
	Investment Name [Low Carbon Energy Project]: TOC Hydrogen Blending Facility		

Investment Description

Enbridge Gas Inc. (EGI) has identified an opportunity which will allow the gas distribution system to contribute towards reducing the environmental impacts of greenhouse gas emissions (GHG) in Ontario by injecting a controlled quantity of hydrogen into the natural gas stream.

This opportunity, which is consistent with the environmental goals of public policy provincially and federally, with EGI's corporate strategy, and with direction provided by the Ontario Energy Board (Board), is called the Low Carbon Energy Project (LCEP or the Project).

The LCEP is a pilot project that will allow the company to green a portion of the natural gas grid in Ontario. The experience gained through the implementation of the LCEP will position EGI to then expand hydrogen injection into other parts of its gas distribution system, further enhancing reductions to GHG emissions across the province by greening the gas distribution system.

- LTC submission, Planning, and design in 2020
- Construction in 2021
- In Service Date: 2021

Assets: New hydrogen blending facility

Related Programs: N/A

Recommended Alternative Description

Scope of Work:
- Install 750 metres of NPS 6 pipeline along Woodbine Avenue and within EGI property.
- Install NPS 2 PE IP and 1st and 2nd cut Station for NGV.
- Install hydrogen blending facility that includes a station, H2 Panel, RTU, HP-IP Stn in the parcel of land next to exisiting TOC compound.
- Disconnect 1 ¼ PE IP gas main and NPS 6 PE IP gas main on Hazelton Avenue and Major Mackenzie Drive to isolate Loop S1 from the rest of Network 3724.
- Back off two stations by reducing pressure at Station 35064A Elgin Mills & Boyd and Station 3136644 Markland and Russell Dawson from 55 psig to 35 psig.
- Leave to Construct application to the Ontario Energy Board will be required.

Resources: Company crews, contractor labour and third-party vendor suppliers

Solution Impact: The LCEP is a pilot project that will allow EGI to green a portion of the natural gas grid in Ontario. The experience gained through the implementation of the LCEP will position EGI to then expand hydrogen injection into other parts of its gas distribution system, further enhancing reductions to GHG emissions across the province by greening the gas distribution system.

Project Timing and Execution Risks:
- LTC submission, Planning, and design in 2020
- Construction in 2021
- In Service Date: 2021
- Execution Risks - approval of materials, pipeline route, budget

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - Growth - Hydrogen Blending
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	30 - Richmond Hill
	Asset Program (EGI)	GTH - Hydrogen Blending
	Asset Class (EGI)	Growth
2. Compliance	Compliance Investment	
	Compliance Justification & Code	
3. Must Do	Must Do Investment	
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (2,622,902)	0.00	$ 3,039,103	1/1/2018

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 2,184,735	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Investment Summary Report	Investment Code	Report Start Year	Number of Years
	19968	2021	5
	Investment Name		
	[Low Carbon Energy Project]: TOC Hydrogen Blending Facility		

Alternative Value - Recommended

Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(2,623)	100%
Total	**(2,623)**	**100%**

ENBRIDGE Investment Summary Report	Investment Code	Report Start Year	Number of Years
	7732	2021	5
	Investment Name: AJAX Reinforcement		

Investment Description

Issue/Concern: Reinforcement projects broadly involve the installation of new or modification of existing gas distribution assets to maintain minimum required system pressure to maintain the capacity to meet customer demand. These projects are primarily driven by customer growth and system reliability considerations. Failure to implement reinforcement projects in a timely manner could lead to a potential inability to support increasing demands of existing customers and the addition of future customers.

Project Purpose/ Need:
- Customer growth data coupled with zoning bylaw and site plan applications suggest that Network 4543 is expected to experience significant load growth.
- System lacks supplementary supply from the northern end of the network; network flexibility is compromised and reliability is a concern during emergency or maintenance situations.
- Due to current system configuration, a NPS 4”steel main (located on Station Street, between Old Station Street and Thomson Street) acts as a bottleneck in the HP system, dropping pressure by approximately 8psi and hindering maximum pressures available downstream at station inlets.

Risk if not completed: System risks without reinforcement:
- Three stations that feed gas into the network will have inlet pressures below the minimum, starting in 2022.
- The low inlet pressures at the stations will inhibit the ability to deliver gas to the network, downstream of the station.
- In 2022 there are approximately 21,120 customers that would be connected to the network that may be impacted.

Assets (preferred option):
- Preferred reinforcement option is comprised of approximately 2.1 kilometres of 6”steel HP pipe along Church Street North, originating from the existing NPS 16”steel Vital Main (at Taunton Road & Church Street North) and terminating at Church Street North and Rossland Road West.
- Two (2) stations need to be installed – 1 station at Church and Taunton and 1 station at Church and Rossland.
- Additionally, 450 metres of 8”PE IP pipe would need to be installed along Rossland Road West, from Church Street North to 120 metres east of Harkins Drive.

Related Programs: N/A

Recommended Alternative Description

Scope of Work:
- Install 2.1 kilometres of 6"ST-HP on Church Street North from Taunton Road (Node 45810115) to Rossland Road W.
- Install two stations - (1) XHP-HP Station at Church & Taunton and (1) HP-IP Station at Church and Rossland.
- Install 450 metres of 8"PE-IP on Rossland Road W, from Church Street to 120 metres east of Harkins Drive.

Resources: Company crews, contractor labour and third-party vendor suppliers.

Solution Impact: This reinforcement project will ensure the system has adequate flow capacity in anticipation of projected customer growth.

Timing: This project is scheduled to be in Service in 2021.

Project Timing and Execution Risks: Risks - weather impacts, resource availability, procurement issues, etc.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - Growth - System Reinforcement
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	40 - Whitby
	Asset Program (EGI)	GTH - System Reinforcement
	Asset Class (EGI)	Growth
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (2,982,124)	0.00	$ 3,212,025	1/1/2020

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 3,103,655	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Investment Summary Report	Investment Code	Report Start Year	Number of Years
	7732	2021	5
	Investment Name		
	AJAX Reinforcement		

Alternative Value - Recommended

Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(2,982)	100%
Total	**(2,982)**	**100%**

Investment Code	Report Start Year	Number of Years
23189	**2021**	**5**

ENBRIDGE

Investment Summary Report

Investment Name

Almonte Reinforcement - Phase 2

Investment Description

Issue/Concern: Reinforcement projects broadly involve the installation of new or modification of existing gas distribution assets to maintain minimum required system pressure, maintain capacity, and meet customer demand. These projects are primarily driven by customer growth and system reliability considerations. Failure to implement reinforcement projects in a timely manner could lead to a potential inability to support increasing demands of existing customers and the addition of future customers.

Project Purpose/Need: This reinforcement addresses issues with the IP network, fed by Almonte District (6A143A) and Scott St. District (6A206A). The interior subdivision piping are undersized, based on the growth predictions of customers' demands. Evidence of densification has become apparent through load sheets. Without the reinforcement, growth cannot be supported in the downstream system.

Pressure issue/concern: The minimum system pressure is forecasted to be infeasible by 2021.
Customer growth issue/ concern: The Phase 1 reinforcement will enable the current system to continue adding new customers after the 10 customers from 2017-2019 as of the proposed in-service date, as per current known 11 customer growth projects equaling 870 m3/hr of load. However, Phase 1 only provides an additional 300m^3/hr capacity for any additional growth outside of this and a Phase 2 reinforcement will be required for further system growth.

Assets: Thee options include 1.2 to 1.3 kilometres of 4" XHP ST, or pressure increase of the system from 30 psi to 55 psi (involves 2.21 kilometres PE IP, 10-15 km ST IP, 350 service replacements, 970 relights, 30 valve replacements).

Related Programs: 21353 (Almonte Reinforcement Phase 1)

Recommended Alternative Description

Scope of Work: 1.2 kilometres of 4" XHP, one district station and will require to install by HDD across the Mississippi River and tie into Carss Street.

Resources: Company crews, contractor labour and third-party vendor suppliers

Solution Impact: The town of Almonte is growing with a majority of the growth on the north end of town, fed by one main which is nearing the limit of its capacity. This side of town is opposite of the high-pressure line separated by the Mississippi River. The pressure for this network is limited to 35 psi.

Project Timing and Execution Risks: According to Network Analysis forecast, this would be required for Winter 2021. Risks: Weather impacts, resource availability, procurement issues, etc.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - Growth - System Reinforcement
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	60 - Ottawa
	Asset Program (EGI)	GTH - System Reinforcement
	Asset Class (EGI)	Growth
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 3	Recommended	$ (3,881,481)	0.00	$ 4,160,000	1/1/2020

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 3,760,000	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended

Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(3,881)	100%
Total	**(3,881)**	**100%**

Investment Code	Report Start Year	Number of Years
16744	2021	5

ENBRIDGE

Investment Summary Report

Investment Name

Amaranth System Reinforcement

Investment Description

Issue/Concern: Reinforcement projects broadly involve the installation of new or modification of existing gas distribution assets to maintain minimum required system pressure to maintain the capacity to meet customer demand. These projects are primarily driven by customer growth and system reliability considerations. Failure to implement reinforcement projects in a timely manner could lead to a potential inability to support increasing demands of existing customers and the addition of future customers.

Project Purpose/ Need: The existing station equipment is inadequate to handle volume flow increase brought by the yearly load LRP growth as projected. Hence, at a certain time it will not be operating efficiently and thus impact the IP downstream. The rebuild of the two stations will mitigate the identified issue. Consequent to the yearly LRP load growth as projected; the HP source at the tail end of the NPS4 ST HP main will be degraded at a certain time. The NPS 8 ST HP main reinforcement will mitigate the identified issue.

Risk if not completed: If the two stations are not rebuilt, downstream pressures will be below the minimum system pressure due to the droop. If the NPS 4 HP ST main is not looped with a larger diameter pipe (NPS 8), the HP minimum inlet pressure will be below the minimum system pressure which again will make the station droop and thus affecting the IP system pressures which will be below the minimum system pressure.

Assets (preferred option):
Phase 1 2021 - Rebuild the district station feeding NW 2176 (RS20031A, Mill Street).
Phase 2 2022 - Rebuild the district station feeding NW 2166 (RS20024A, Melody Lane).
Phase 3 2024 - Install approximately 5000 metres NPS 8 ST HP Main Reinforcement on Sideroad 5 from Crago Station Outlet main road to 5th Line.

Related Programs: N/A

Recommended Alternative Description

Scope of Work:
Phase 3
- Install app 5000 metres NPS 8 ST HP Main Reinforcement on Sideroad 5 from Crago Station Outlet main road to 5th Line.

Solution Impact: This reinforcement project will ensure the system has adequate flow capacity in anticipation of projected customer growth.

Resources: Company crews, contractor labour and third-party vendor suppliers.

Project Timing and Execution Risks: Scheduled to be in service in 2024
Risks: Weather impacts, resource availability, procurement issues, etc.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - Growth - System Reinforcement
Investment Stage	Long Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	20 - Mississauga
	Asset Program (EGI)	GTH - System Reinforcement
	Asset Class (EGI)	Growth
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (6,871,221)	0.10	$ 10,294,684	1/1/2021

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 200,000	$ 200,000	$ -	$ 9,894,684	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ 107,046	$ -

ENBRIDGE

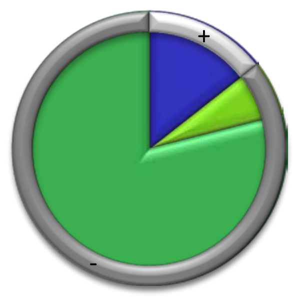
Investment Summary Report

Investment Code	Report Start Year	Number of Years
16744	**2021**	**5**

Investment Name

Amaranth System Reinforcement

Alternative Value - Recommended



	Value Function Measure	**Value**	**Value in Percentage**
■	Revenue Impact (CA)	1,395	14%
■	Financial Risk	0	0%
■	Public Safety Risk	0	0%
■	Budget Savings OPEX (CA)	(637)	7%
■	Total Investment Cost (CA)	(7,630)	79%
	Total	**(6,871)**	**100%**

ENBRIDGE **Investment Summary Report**	Investment Code **1024**	Report Start Year **2021**	Number of Years **5**
	Investment Name Rideau Reinforcement		

Investment Description

Issue/Concern: Reinforcement projects broadly involve the installation of new or modification of existing gas distribution assets to maintain minimum required system pressure, maintain capacity and meet customer demand. These projects are primarily driven by customer growth and system reliability considerations. Failure to implement reinforcement projects in a timely manner could lead to a potential inability to support increasing demands of existing customers and the addition of future customers.

This network in Ottawa is predominantly made up of residential and commercial customers. In the current configuration, a high pressure network is exclusively fed by both the Ottawa and Richmond Gate Stations. Network Analysis has identified an upstream flow constraint at the Ottawa Gate Station, along with a bottleneck constraint for gas fed from Richmond Gate Station. The South outlet of Ottawa Gate can be set to as low as 400 psig (normally 470 psig) while Richmond Gate is kept at 470 psig, thus flowing more gas from the west to the east.

The preferred option is to not rely on system biasing (temporary reduction in station pressure to adjust flows) and keep Ottawa South station set at 470 psig. Additionally, in the current configuration, an existing NPS 12 high pressure pipeline along Fallowfield Road is a bottleneck for gas flowing from the west, to Richmond Gate Station, and to eastern areas. The previously constructed Ottawa Reinforcement Plan (ORP) Phase 1 as well as the Strandherd River crossing has helped move gas from Richmond Gate eastward to areas of concentrated and growing gas demand.

This reinforcement will assist in moving additional gas from Richmond Gate toward the areas that would be serviced by Ottawa Gate, and remove the bottleneck constraint. There are approximately 193,553 customers on the associated networks in 2016.

Assets: A combination of Pipe and Station assets to meet project objectives.

Related Programs: N/A

Recommended Alternative Description

Scope of Work:
The proposed scope includes the installation of 7 kilometres of NPS 20 high pressure main from Greenbank Road and W Hunt Club Road to Princess of Wales Drive and W Hunt Club Road along W Hunt Club Road.

Solution Impact: This reinforcement project will ensure the system has adequate flow capacity in anticipation of projected customer growth.

Resources: Company crews, contractor labour and third-party vendor suppliers.

Project Timing and Execution Risks:
The Project is proposed to start in 2021 and be completed by 2025.
Risks: Weather impacts, resource availability, procurement issues, etc.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - Growth - System Reinforcement
Investment Stage	Long Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	60 - Ottawa
	Asset Program (EGI)	GTH - System Reinforcement
	Asset Class (EGI)	Growth
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

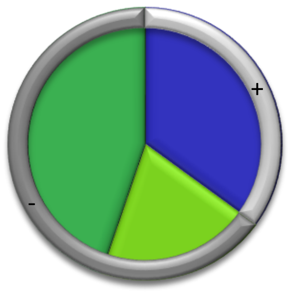
Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (24,506,425)	0.33	$ 53,489,000	1/1/2023

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ -	$ -	$ 268,000	$ 5,348,000	$ 47,070,000
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Investment Summary Report	Investment Code **1024**	Report Start Year **2021**	Number of Years **5**
	Investment Name Rideau Reinforcement		

Alternative Value - Recommended



	Value Function Measure	Value	Value in Percentage
■	Revenue Impact (CA)	28,709	35%
■	Financial Risk	0	0%
■	Public Safety Risk	0	0%
■	Budget Savings OPEX (CA)	(16,544)	20%
■	Total Investment Cost (CA)	(36,672)	45%
	Total	**(24,506)**	**100%**

ENBRIDGE Investment Summary Report	Investment Code	Report Start Year	Number of Years
	16751	2021	5
	Investment Name: Thornton Reinforcement		

Investment Description

Issue/Concern:
Reinforcement projects broadly involve the installation of new or modification of existing gas distribution assets to maintain minimum required system pressure, maintain capacity and meet customer demand. These projects are primarily driven by customer growth and system reliability considerations. Failure to implement reinforcement projects in a timely manner could lead to a potential inability to support increasing demands of existing customers and the addition of future customers.

Project Purpose/ Need: Customer growth in the surrounding area will drive this reinforcement. Increase in load will cause tail end pressures to go below the minimum pressure of 100 psi without reinforcement.

Risk if not completed: This reinforcement will limit the risk of customer loss up to forecast temperatures under normal operating conditions. Customer additions might be limited if this reinforcement is not completed.

Assets (preferred option):
Phase 1 in 2022: Proposed 2.5 kilometres of 12" SC on Innisfil Beach Road, from Thornton Gate Station #3613819 outlet to County Road 53
Phase 2 in 2024: Proposed 6 kilometres of 8" SC on Lockhart Road, from tail end of existing 8" SC at Lockhart Road/Yonge Street to 25 Sideroad

Related Programs: N/A

Recommended Alternative Description

Scope of Work:
-Phase 1 in 2022, Proposed 2.5 kilometres of 12" SC XHP on Innisfil Beach Road, from Thornton Gate Station #3613819 outlet to County Road 53
-Phase 2 in 2024 Proposed 6 kilometres of 8" SC XHP on Lockhart Road, from tail end of existing 8" SC XHP at Lockhart Road/Yonge Street to 25 Sideroad

Solution Impact: This reinforcement project will ensure the system has adequate flow capacity in anticipation of projected customer growth.

Resources: Company crews, contractor labour, and third-party vendor suppliers.

Project Timing and Execution Risks: This project is scheduled to be in service in 2023.
Risks: Weather impacts, resource availability, procurement issues, etc.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - Growth - System Reinforcement
Investment Stage	Long Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	50 - Barrie
	Asset Program (EGI)	GTH - System Reinforcement
	Asset Class (EGI)	Growth
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (8,914,106)	0.00	$ 10,935,636	1/1/2022

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ -	$ 3,669,622	$ 7,266,014	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ 89,414	$ 96,132	$ -	$ -

Alternative Value - Recommended

Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(8,914)	100%
Total	**(8,914)**	**100%**

Investment Summary Report	Investment Code	Report Start Year	Number of Years
	1213	2021	5
	Investment Name: York Region Reinforcement		

Investment Description

Issue/Concern: Reinforcement projects broadly involve the installation of new or modification of existing gas distribution assets to maintain minimum required system pressure, maintain capacity, and meet customer demand. These projects are primarily driven by customer growth and system reliability considerations. Failure to implement reinforcement projects in a timely manner could lead to a potential inability to support increasing demands of existing customers and the addition of future customers.

Number of customers impacted by year:
The growth projection for this project (suite of pipes and stations over time) is in the value framework and reproduced below. Only totals are provided by year.

2018	2881
2019	1679
2020	1532
2021	1253
2022	1111
2023	1132
2024	1107
2025	1036
2026	1026
2027	1069
2028	1101

Length and diameter of pipe to be installed:
2022: 5.4 kilometres of NPS 12
2024: 4 kilometres of NPS 6
2026: 7.6 kilometres NPS 12

Assets: A combination of Pipe and Station assets to meet project objectives.

Related Programs: N/A

Recommended Alternative Description

Scope of Work:
2018: Rebuild Glenwoods and Woodbine Station (3546065) so that it has a differential of 35 psi or less.
2018: Rebuild Doane & Woodbine Station (2937273) so it has a differential of 50 psi or less and can handle the existing capacity.
2019: Install 2.1 kilometres of 4” high pressure pipe on Civic Centre Road from Baseline Road to 200 meters south of Metro Road N.
2022: Install 5.4 kilometres of 12” high pressure pipe starting at Bondhead Gate station and replacing the existing 6” high pressure pipe all the way to the intersection of Hwy 88 and 10th Line. This may result in the requirement for a rebuild of Bondhead Gate Station for capacity reasons, pending confirmation of the max station throughput.
2024: Install 4.0 kilometres of 6” high pressure pipe on Baseline Road from McCowan Road to Dalton Road, north along Dalton Road to Black River Road, east along Black River Road to Station 3872873.
2026: Install 7.6 kilometres of 12” high pressure pipe on Bathurst Street from Gamble Road to McClellan Way. Install 7.1 kilometres of 8” SC high pressure pipe on Bathurst Street from McClellan Way to Mulock Drive. Install one XHP to HP Station at Bathurst Street and Bloomington Road.
2026: IP HP pressure elevation must be completed.
1. Elevate IP to HP new district stations
- 1 station at Bathurst Street and Mulock Road
- 1 HP to IP station at Bathurst Street and William Dunn Crescent
- 1 HP to IP station at Mulock Drive and Yonge Sever IP locations
- Bathurst Street and Keith Avenue
- Mulock Drive and Columbus - Way Elevate IP to HP
- NPS12, NPS8, NPS4 and NPS2 main – approximately 7 kilometres
- Main located on Bathurst Street, Mulock Drive, 19th Sideroad and Old Bathurst Street
If the engineering assessment indicates that IP cannot be elevated to HP, the following must be completed instead: Install 1.7 kilometres of 8” SC high pressure pipe on Mulock Drive from Bathurst Street to Yonge Street.
Install XHP-HP station at Bathurst and Mulock. Install HP-IP station at Yonge and Mulock.

Solution Impact: This reinforcement project will ensure the system has adequate flow capacity in anticipation of projected customer growth.

Resources: Company crews, contractor labour, and third-party vendor suppliers

Project Timing and Execution Risks: This multi-year project will be phased in each year from 2021 to 2026
Risks: Weather impacts, resource availability, procurement issues, etc.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - Growth - System Reinforcement
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	30 - Richmond Hill
	Asset Program (EGI)	GTH - System Reinforcement
	Asset Class (EGI)	Growth
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
1213	2021	5

Investment Name

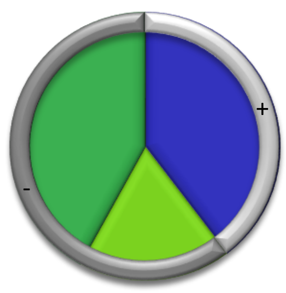
York Region Reinforcement

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (22,997,686)	0.51	$ 65,846,000	1/1/2020

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 2,656,000	$ 15,400,000	$ 280,000	$ 6,260,000	$ 1,280,000
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Revenue Impact (CA)	43,957	40%
Financial Risk	0	0%
Public Safety Risk	0	0%
Budget Savings OPEX (CA)	(20,384)	18%
Total Investment Cost (CA)	(46,571)	42%
Total	**(22,998)**	**100%**

Distribution Pipe

Investment Code	Report Start Year	Number of Years
100504	2021	5

Investment Summary Report

Investment Name

A10: Kipling Ave & Lake Shore Blvd W, Etobicoke, Replacement

Investment Description

Issue/Concern:

General Concerns:
Vintage Steel Replacement Program: Proactive replacement program to renew aging vintage steel pipe assets before reaching end-of-life. Vintage steel mains have shown signs of declining health due to the cumulative effective of poor manufactured coating performance, construction practices, latent third-party damages to pipe coating, and the effect of stray currents from transit infrastructure such as subway and streetcars. The current failure projection model is forecasting an exponential increase in the number of corrosion related failures, while the C55 value framework and the 40-year risk projection are showing an aggressive increase in the safety risk associated with steel main failures. Vintage steel systems also have potential to include: compression couplings, shallow installation depth and shallow assemblies making pipe susceptible to third party damage, and manufactured defects associated with seam welds and fittings.

Site-specific Concerns:
A 1955 vintage NPS 8 HP steel main is susceptible to the issues outlined above. Operations field personnel reported past stray current issues from the streetcar tracks and their roundabout. Combining with coating holidays on the steel main, the stray current could negatively affect the cathodic protection effectiveness and causing accelerated corrosion on the steel main. The NPS 8 gas main traverses in a highly-populated, residential area in downtown Toronto, which could drive up the consequence in the event of a failure.
An urgent section is identified near Humber College, where stray current from streetcar tracks is causing corrosion issues on the steel pipe. The number of repairs that have been done has caused Operations to flag the section. By replacing the steel HP pipe with plastic IP pipe, this corrosion issue can be avoided.

Assets: Steel main on Lake Shore Boulevard and Kipling Avenue

Related Programs: N/A

Recommended Alternative Description

Scope: Replace 883 metres of 2" SC HP GM, 557 metres of 4" SC HP GM and 173 metres of 8" SC HP GM with approximately 1628 metres of 4" PE IP GM. Approximately 29 customers affected (28 Services + 1 Header. 10 Meter Relites).

Resources: NPL

Solution Impact: Eliminate risk by replacing steel HP pipe with polyethylene IP pipe to avoid corrosion issues.

Project Timing: Planning in 2020, execution in 2021.

Execution Risks: No TRCA permit required. Moratorium expires in 2022. Urgent section needs to be replaced therefore a moratorium exception may be required to get this work done in 2021 as per AR&I's request.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - DP - Main Replacement - Vintage Steel Mains Replacement Program
Investment Stage	Short Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	10 - Toronto
	Asset Program (EGI)	DP - Main Replacement
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 2	Recommended	$ (1,294,978)	0.43	$ 2,443,077	1/1/2021

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 2,443,077	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ 755,591	$ -	$ -	$ -	$ -

Investment Summary Report

Investment Code	Report Start Year	Number of Years
100504	2021	5

Investment Name

A10: Kipling Ave & Lake Shore Blvd W, Etobicoke, Replacement

Alternative Value - Recommended

Value Function Measure	Value	Value in Percentage
Public Safety Risk	2,865	35%
Cost Avoidance OPEX (CA)	890	11%
Financial Risk	764	9%
Operational Risk	489	6%
Reputational Risk	462	6%
Avoided GHG Emissions (CA)	327	4%
Employee And Contractor Safety Risk	143	2%
Budget Savings OPEX (CA)	77	1%
Cost Avoidance CAPEX (CA)	0	0%
Environmental Risk And Remediation	0	0%
Total Investment Cost (CA)	(2,262)	27%
Total	**3,755**	**100%**

ENBRIDGE Investment Summary Report	Investment Code **101343**	Report Start Year **2021**	Number of Years **5**
	Investment Name A60: Sparks St, Ottawa, Replacement		

Investment Description

Issue/Concern:
Sparks Street's NPS 12 steel main is approaching end-of-life and a replacement is necessary. This main was installed in the 1960s and 1970s and has compression couplings, Dresser-style fittings, drips and blow off valves. Sparks Street is a pedestrian path through the downtown core of Ottawa with no vehicular access, therefore performing maintenance activities or accessing the site during emergencies is a challenge.

Assets: Approximately 1100 metres of NPS 12 intermediate pressure (IP) steel pipe on Albert Street, 900 metres of NPS 4 IP Polyethylene (PE) pipe on Sparks Street and 175 metres of NPS 4 PE pipe from Lyons to Wellington.

Related Programs: N/A

Recommended Alternative Description

Scope of Work:This pipeline project involves installing approximately 1100 metres of NPS 12 intermediate pressure (IP) steel pipe on Albert Street, 900 metres of NPS 4 IP Polyethylene (PE) pipe on Sparks Street and 175 metres of NPS 4 PE pipe from Lyons to Wellington. Due to the Parliament Hill location, construction will be slow and permitting / accessibility issues will not allow for a single year construction project.

Resources: Regional planners and construction crews.

Solution Impact: Replacing the main will ensure the continued operation of EGI's gas distribution system, and will mitigate safety risks to employees, contractors, and general public.

Project Timing and Execution Risk: Planning of the project has commenced in Q1 of 2020, proposed construction date is Q2 of 2021 (earliest) and proposed in-service date is Q4 2020.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - DP - Main Replacement - Vintage Steel Mains Replacement Program
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	60 - Ottawa
	Asset Program (EGI)	DP - Main Replacement
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	
	Compliance Justification & Code	
3. Must Do	Must Do Investment	
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

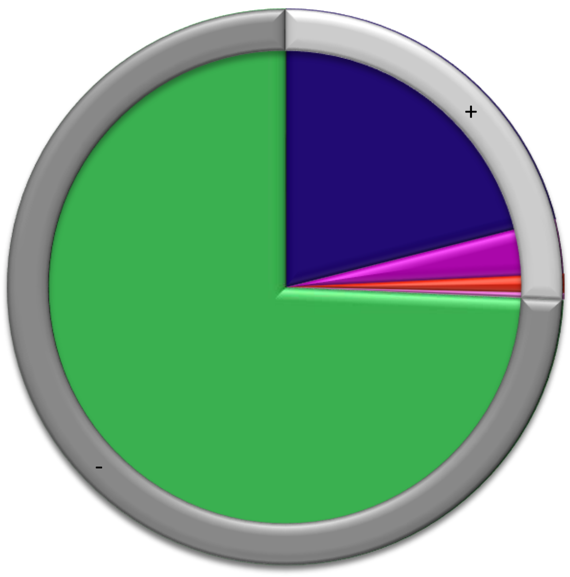
Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
NPS 12 Replacement	Recommended	$ (5,563,120)	0.28	$ 9,326,660	1/1/2020

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 2,305,000	$ 2,305,000	$ 2,305,000	$ 2,203,580	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Investment Summary Report	Investment Code	Report Start Year	Number of Years
	101343	2021	5
	Investment Name: A60: Sparks St, Ottawa, Replacement		

Alternative Value - Recommended



	Value Function Measure	Value	Value in Percentage
	Cost Avoidance CAPEX (CA)	2,204	21%
	Financial Risk	333	3%
	Public Safety Risk	114	1%
	Reputational Risk	37	0%
	Avoided GHG Emissions (CA)	3	0%
	Budget Savings OPEX (CA)	1	0%
	Operational Risk	0	0%
	Employee And Contractor Safety Risk	0	0%
	Cost Avoidance OPEX (CA)	0	0%
	Environmental Risk And Remediation	0	0%
	Budget Savings CAPEX (CA)	0	0%
	Revenue Impact (CA)	0	0%
	Total Investment Cost (CA)	(7,768)	74%
	Total	**(5,076)**	**100%**

ENBRIDGE Investment Summary Report	Investment Code 23230	Report Start Year 2021	Number of Years 5
	Investment Name Black Creek Rd and River Trail, Fort Erie - VPM Aldyl-A MP lined in steel		

Investment Description

Issue/Concern:
General: Vintage Plastic Replacement Program: Proactive replacement program to renew aging vintage plastic pipe assets before reaching end-of-life. Vintage plastic Aldyl A mains are the earliest plastic mains used within the distribution system; the installation period of Aldyl A plastics started in the late 1960s on a field trial basis and was concluded by the end of 1976 for the EGD rate zone and 1984 for the Union rate zones. It is well known and studied in the North American gas industry that Aldyl A plastic mains have brittle-like cracking properties. The oxidation of the inner wall surface during manufacturing (also known as Low Ductile Inner Wall (LDIW)) and the large spherulites found in its microstructure causes pipe to be susceptible to cracking and premature failure in the presence of stress intensifiers such as a large number of connections, squeeze-off locations, and the presence of rock impingement points caused by rocky soil types.

Site specific: MP vintage plastic main lined within old steel mains. If pipe is damaged or leaks, the migration path could cause gas to travel long distances. Difficult to pinpoint leaks and increased risk of migration into other conduits/utilities.

Assets: Black Creek Road and River Trail, Fort Erie - VPM Aldyl-A MP lined in steel

Project proposed: 2235 metres NPS 4” PE IP, 8200m NPS 2” PE IP, 277 Service Relays (MP to IP), 18 Service Relays (IP to IP); Abandonment: 8200 metres MP Main (Various Sizes), 632 metres IP Main (4” & 3”), 277 MP Services, 18 IP Services.

Related Program: N/A

Recommended Alternative Description

Scope of Work: Project proposed: 2235 metres NPS 4” PE IP, 8200 metres NPS 2” PE IP, 277 Service Relays (MP to IP), 18 Service Relays (IP to IP); Abandonment: 8200 metres MP Main (Various Sizes), 632 metres IP Main (4” & 3”), 277 MP Services, 18 IP Services.

Resources: District operations is planning and is constructing this project utilizing extended alliance partner NPL.

Solution Impact: The existing vintage plastic pipe will be removed from EGI system.

Project Timing and Execution Risks: Work is planned to be completed over two years and starting with survey and design 2020 and execution 2021/22. Cost estimates continue to be refined as project design progresses and approaches construction. Depending on the location of the work, the project might require temporary land rights acquisition and special permitting ahead of execution, which could have an impact to the project schedule.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - DP - Main Replacement - Vintage Plastic Replacement Program
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	80 - Niagara
	Asset Program (EGI)	DP - Main Replacement
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (3,939,405)	0.00	$ 4,414,980	1/1/2019

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 2,174,990	$ 2,174,990	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ 720,508	$ 720,508	$ -	$ -	$ -

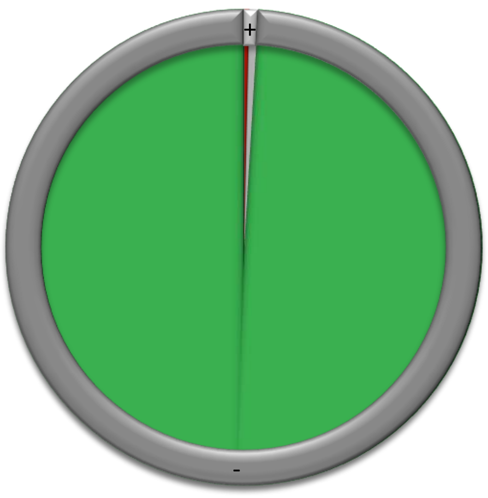
Investment Summary Report

Investment Code	Report Start Year	Number of Years
23230	**2021**	**5**

Investment Name

Black Creek Rd and River Trail, Fort Erie - VPM Aldyl-A MP lined in steel

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Public Safety Risk	13	0%
Avoided GHG Emissions (CA)	7	0%
Operational Risk	5	0%
Financial Risk	4	0%
Reputational Risk	4	0%
Cost Avoidance OPEX (CA)	2	0%
Budget Savings OPEX (CA)	2	0%
Employee And Contractor Safety Risk	1	0%
Cost Avoidance CAPEX (CA)	0	0%
Environmental Risk And Remediation	0	0%
Total Investment Cost (CA)	(3,944)	99%
Total	**(3,905)**	**100%**

	Investment Code	Report Start Year	Number of Years
ENBRIDGE **Investment Summary Report**	**21947**	**2021**	**5**
	Investment Name Burleigh Rd Fort Erie - Replacement		

Investment Description

Issue/Concern:
This area (Hyman Avenue, Fort Erie) is very low and wet; with through-wall corrosion on the LP steel mains, water was able to get into the main and services on Hyman Avenue and is disrupting gas service to customers. This low pressure (LP) network consists of 1960s black-coated and 1970s vintage mains. Some LP to intermediate pressure (IP) replacement has already completed over past 20 years due to corrosion leaks.
Phase 2 of the Hyman Ave Fort Erie replacement will see the replacement of 8125 meters of existing LP pipe (combination of ST and PE, NPS 2, 3 and 4). In addition to replacing this pipe, the area will be tied into IP Network 8120, relaying 415 services, and tying over another 75 services. Any previous steel installation in this area will also be replaced for corrosion purposes as part of Phase 2. Phase 2 will also see the abandonment of two stations (IP to LP).

Assets: 8125 metres of existing LP pipe (combination of ST and PE, NPS 2, 3 and 4) on Hyman Avenue, Fort Erie.

Related Programs: N/A

Recommended Alternative Description

Scope of Work:
Phase 2 of the Hyman Avenue Replacement will see the replacement of 8125 metres of existing LP pipe (combination of NPS 2,3, and 4 both polyethylene (PE) and steel). In addition to replacing this LP pipe, it will also be tied over to IP Network 8120, relaying 415 services, and tying over 75 services.

Proposed approx. 1,400 metres of NPS 4 PE IP and 14,800 metres of NPS 2 PE IP.

Resources: Project will be executed with extended alliance contractor resources.

Solution Impact: Replacing this vintage steel pipe will ensure the continued operation of EGI's gas distribution system, and will mitigate safety risks to employees, contractors, and the general public.

Project Timing and Execution Risks: Survey and planning in 2019 approved, execution in 2020/2021. Cost estimates continue to be refined as project design progresses and approaches construction. Depending on the location of the work, the project might require temporary land rights acquisition and special permitting ahead of execution, which could have an impact to the project schedule.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - DP - Main Replacement - Vintage Steel Mains Replacement Program
Investment Stage	Executing		

Investment Overview

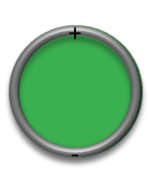
1. Project Information	State/Province	Ontario
	Operating Area (EGI)	80 - Niagara
	Asset Program (EGI)	DP - Main Replacement
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (4,826,853)	0.00	$ 5,140,632	1/1/2019

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 3,641,872	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ 423,465	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(4,827)	100%
Total	**(4,827)**	**100%**

ENBRIDGE Investment Summary Report	Investment Code	Report Start Year	Number of Years
	1938	**2021**	**5**
	Investment Name: NPS 10 Glenridge Avenue, St. Catharines		

Investment Description

Issue/Concern:
GENERAL CONCERNS: Vintage steel mains have shown signs of declining health due to the cumulative effective of poor manufactured coating performance, construction practices, latent third party damages to pipe coating, and the effect of stray currents from transit infrastructure such as subway and streetcars. The current failure projection model is forecasting an exponential increase in the number of corrosion related failures, while the C55 value framework and the 40-year risk projection are showing an aggressive increase in the safety risk associated with steel main failures.

SITE SPECIFIC CONCERNS:
This project looks to replace approximately 8.7 kilometres of mostly 1954 to 1960s vintage NPS 10 intermediate pressure (IP) pipe with sections of NPS 12 and NPS 8 spliced in over the years as repairs. Fittings and equipment are not readily available with some NPS 10 components taking several months to a year to receive if needed for repair / replacement. It is difficult to identify all possible fittings that may be required for repair work and expensive to sustain an extensive warehouse of components. For example, a recent repair that typically would have used a Shortstop 3-way tee could not be used once the pipe was excavated due to shallow depth of cover. Instead, a TDW spherical 3-way tee needed to be used.

Depth of cover (DOC) is a significant issue throughout the NPS 10 system. A 2019 DOC survey found that 366 (33%) survey locations had less than 90 cm of cover, and 90 survey locations (8%) had DOC<60cm, with one location found having exposed pipe due to creek erosion. Poor depth of cover leads to increased third-party damages (as has been seen with blow-off valves). Other risk factors include black coal tar pipe coatings used on 1959/1960 vintage NPS 10 pipe which show evidence of degradation, yielding to corrosion.

There are many unusual fittings (Stop-and-Go) and unusual construction practices (such as using unrestrained compression couplings to tie in service connections) that can lead to difficult emergency responses. For example, a recent leak repair took 24 days to complete at a cost of almost $500K due to complications from DOC, components, and construction practices. Unrestrained compression couplings have been the source of leaks due to ground settlement and increase the risk of pull-out. The river crossing at Twelve Mile Creek is very difficult to access due to steep creek banks and heavy vegetation, making it difficult to perform cathodic protection and leak surveys. It will pose as a significant concern for any required emergency response. The numerous transitions from NPS 8 to NPS 10 to NPS 12 also creates concern and difficulties for operational work to be completed.

There are two main line valves that are suspected to be tied in with unrestrained compression couplings (CC) as per an Integrity Assessment for suspect CC locations. Cathodic protection for some of the NPS 10 segments has been historically poor, showing as much as 25% of historical readings over the last 20 years below minimum required levels.

Assets:
8.7 kilometres of mostly 1954 to 1960s vintage NPS 10 IP pipe with sections of NPS 12 and NPS 8 spliced in over the years as repairs that run along Glenridge Avenue from Russel Avenue south to Lockhart Drive, then along Lockhart Drive west to First Street Louth.

Related Programs: N/A

Recommended Alternative Description

SCOPE OF WORK: AR&I Main Replacement - Replace approximately 7500 m of vintage main NPS 10" ST IP and approx 110 service connections with NPS 8 PE.

RESOURCES: External Alliance contractors

SOLUTION IMPACT:
Main replacement project identified by Operations - Pipelines as high-priority. Replacement is required due to age, pipeline condition and risk assessment results.

PROJECT TIMING & EXECUTION RISKS:
This confirmed the timing for execution of this replacement project for 2024/25.
Execution Risks: Moratoriums, 3rd party developments, COVID-19 impacts, permitting and required easements.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - DP - Main Replacement - Vintage Steel Mains Replacement Program
Investment Stage	Long Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	80 - Niagara
	Asset Program (EGI)	DP - Main Replacement
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

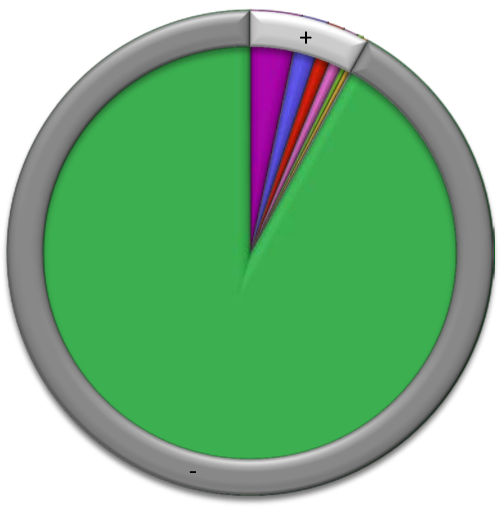
Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
NPS 8 PE option	Recommended	$ (8,367,776)	0.00	$ 11,804,455	1/1/2023

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ -	$ -	$ 435,000	$ 5,912,929	$ 5,456,526
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ 3,565,604

Investment Summary Report	Investment Code	Report Start Year	Number of Years
	1938	2021	5
	Investment Name		
	NPS 10 Glenridge Avenue, St. Catharines		

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Financial Risk	308	3%
Avoided GHG Emissions (CA)	157	2%
Public Safety Risk	105	1%
Reputational Risk	85	1%
Budget Savings OPEX (CA)	37	0%
Operational Risk	36	0%
Employee And Contractor Safety Risk	11	0%
Cost Avoidance CAPEX (CA)	0	0%
Cost Avoidance OPEX (CA)	0	0%
Environmental Risk And Remediation	0	0%
Total Investment Cost (CA)	(8,405)	92%
Total	**(7,666)**	**100%**

ENBRIDGE Investment Summary Report	Investment Code	Report Start Year	Number of Years
	22444	2021	5
	Investment Name: NPS 12 & NPS 8 Blackhorse Gate to Chippewa Creek NW8983 Retrofit		

Investment Description

Issue/Concern:

Project Specific: NPS 12 and NPS 8 Blackhorse Gate to Chippewa Creek NW8983 pipeline has been identified for inclusion in the Integrity Management Program (IMP), according to TSSA CAD, FS-220-16, Clause 10.3.11, as identified by the MOP team. If the pipelines are operating above 29.5% SMYS, they fall within the definition of an IMP pipeline that is in scope of EGI's Integrity Management Program.

General: The Integrity Retrofit portion of the Integrity Management Program is to specifically capture retrofit work to make pipelines inline inspectable. The Integrity Management Program is a mandated regulatory requirement which has been designed to comply with all applicable codes and standards. The program consists of the regular assessment and maintenance of the integrity of pipeline systems at EGI to ensure their continued safety and reliability. Most of the expenditure included in this category is for pipelines that operate above 30% SMYS. It includes installation costs for permanent in-line inspection (ILI) tool launcher and receiver facilities, retrofits to existing lines to remove restrictive fittings or pipe configurations so they can be inspected with ILI tools, and remediation of pipeline segments with integrity issues that are identified through the inspections.

Assets: NPS 12 and NPS 8 Blackhorse Gate to Chippewa NW8983

Related Programs: N/A

Recommended Alternative Description

Scope of Work:
The following retrofits are required: Install One NPS 12 above-ground launcher isolation valve kicker and permanent trap. Remove IPSCO fitting at outlet of gate station. (one site, two digs); Install one below-ground NPS 12 receiver isolation valve and two below-ground NPS 8 launcher isolation valves. (Trap and kicker line will be temporary) (one site); Install Two NPS 8 below-ground receiver isolation valves and kicker line valves (trap and kicker line will be temporary). Remove spherical at inlet to the station at one of these sites FN 8-585-95 (two sites); Remove NPS 8 Rockwell plug valve. FN 8-227-118 (One site); Remove Mueller line stopper, Rockwell plug valve, reconfigure tie-in. FN 8-228-2 (possibly part of below-ground receiver isolating valve installation); Remove two Mueller line stopper fittings, reconfigure tee at Tie-in of NPS 12 reinforcement 8N1013-2 (one site).

Solution Impact: The NPS 12 and NPS 8 Blackhorse Gate to Chippewa Creek NW8983 lines can be in-line inspected after the retrofit work, ensuring compliance of the EGI TIMP and the safe and reliable operation of the pipeline.

Resources: Engineering Construction will manage the planning and execution of this project.

Project Timing and Execution Risks: Cost estimates continue to be refined as project design progresses and approaches construction. Depending on the location of the work, the project might require temporary land rights acquisition and special permitting ahead of execution, which could have an impact to the project schedule.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - DP - Integrity - Integrity Retrofit
Investment Stage	Long Term Planning		

Investment Overview

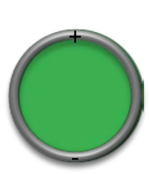
1. Project Information	State/Province	Ontario
	Operating Area (EGI)	80 - Niagara
	Asset Program (EGI)	DP - Integrity
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	Yes
	Compliance Justification & Code	
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1: Retrofit	Recommended	$ (3,496,902)	0.00	$ 3,883,883	1/1/2021

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 2,436,291	$ 1,447,592	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(3,497)	100%
Total	**(3,497)**	**100%**

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
22445	2021	5

Investment Name

NPS 12 & NPS 8 Blackhorse to Forks Rd NW8980 Retrofit

Investment Description

Issue/Concern:

General: The Integrity Retrofit portion of the Integrity Management Program is to specifically capture retrofit work to make pipelines inline inspectable. The Integrity Management Program is a mandated regulatory requirement which has been designed to comply with all applicable codes and standards. The program consists of the regular assessment and maintenance of the integrity of pipeline systems at EGI to ensure their continued safety and reliability. Most of the expenditure included in this category is for pipelines that operate above 30% SMYS. It includes installation costs for permanent in-line inspection (ILI) tool launcher and receiver facilities, retrofits to existing lines to remove restrictive fittings or pipe configurations so they can be inspected with ILI tools, and remediation of pipeline segments with integrity issues that are identified through the inspections.

Project-specific Concerns: NPS 12 and NPS 8 Blackhorse Gate to Forks Road NW8980 pipeline has been identified for inclusion in the Integrity Management Program (IMP), according to TSSA CAD, FS-220-16, Clause 10.3.11, as identified by the MOP team. If the pipelines are operating above 29.5% SMYS, they fall within the definition of an IMP pipeline that is in scope of EGI's Integrity Management Program.

Assets: Network #NW8980 NPS 12 and 8 Blackhorse to Forks Road

Related Programs: N/A

Recommended Alternative Description

Scope of Work:
NPS 8: Install two below-ground launcher isolation valve and kicker line valve. (Trap and kicker line will be temporary) (tw sites); Install two above-ground receiver isolation valve and kicker line valve, and permanent trap. (2 sites); Remove two Mueller line stoppers, FN 8-263-1-4 (one site, two digs); Remove NPS 8 Mueller line stopper at station tie-in FN 8-342-125 (1 site); Check configuration of piping to remove NPS 6 bottleneck, FN 8-771-182; Remove NPS 8 spherical FN 8-491-8-10 (one site)
NPS 12: Install one above-ground launcher isolation valve, kicker line and permanent trap. (one site); Install one above-ground receiver isolation valve, kicker line and permanent trap. (one site); Remove two Mueller line stoppers FN 8-275-101,102 (one site, two digs); NPS 12 valve Kerotest, planning needs to confirm. Plug valve needs to be removed, FN 8-62-73A; Remove two Mueller line stoppers, FN 8-266-77-79 (one site, two digs); Remove two Mueller line stoppers and insulating flange set, replace with weld-in insulator FN 8-353-41-44 (one site, two digs); Install solid piggable insert into Mueller line stopper fitting. FN-461-23-26 (one site)

Solution Impact: The NPS 12 and NPS 8 Blackhorse to Forks Road lines can be in-line inspected after the retrofit work, ensuring compliance of the EGI TIMP and the safe and reliable operation of the pipeline.

Resources: Engineering Construction will manage the planning and execution of this project.

Project Timing and Execution Risks: Cost estimates continue to be refined as project design progresses and approaches construction. Depending on the location of the work, the project might require temporary land rights acquisition and special permitting ahead of execution, which could have an impact to the project schedule.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - DP - Integrity - Integrity Retrofit
Investment Stage	Long Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	80 - Niagara
	Asset Program (EGI)	DP - Integrity
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	Yes
	Compliance Justification & Code	Compliance to TIMP program as this line is identified as operating > 30% SMYS.
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1: Retrofit	Recommended	$ (5,992,100)	0.00	$ 6,714,513	1/1/2021

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 3,433,404	$ 3,281,109	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended

Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(5,992)	100%
Total	**(5,992)**	**100%**

Investment Code	Report Start Year	Number of Years
10086	2021	5

ENBRIDGE

Investment Summary Report

Investment Name

NPS 12 Martin Grove Rd - Clements Rd to Lavington

Investment Description

General Concerns:
Vintage steel mains have shown signs of declining health due to the cumulative effects of poorly manufactured coatings, construction practices, latent third-party damages to pipe coatings and the effect of stray currents from transit infrastructure (such as the subway and streetcars). The current failure projection model forecasts an exponential increase in the number of corrosion-related failures. The C55 value framework and the 40-year risk projection show an aggressive increase in the safety risk associated with steel main failures. In addition to age, vintage steel mains are also susceptible to accelerated degradation and or higher risk of third-party damage in the following ways:
-Compression couplings
-Shallow blow-off valve assemblies that could be damaged during excavation activities
-Reduction in the original depth of cover
-Continuous exposure to road salt and seasonal ground movement on bridge crossing assets
-Lack of cathodic protection on pipe casings that could result in corrosion and could lead to the loss of containment
-Manufacturing defects associated with seam welds and fittings that could result in a loss of containment due to prolonged stress and corrosion
-Latent damages to pipe coatings that were never reported to EGI for repair and became active corrosion sites, resulting in accelerated corrosion and potentially loss of containment

Site-specific Concerns:
The Martin Grove project is a size for-size replacement of NPS 12 HP steel main on Martin Grove Road. There are a number of service connections tied into the high pressure main where vintage field applied coatings become a corrosion inducing location due to degradation. For example, an opportunistic dig along this main for a service connection found a corrosion pit under the field applied coating at a tee. Further, this main has coal tar coating which is know to disbond and create corrosion concerns. Depth of cover is a significant concern, where a 2018 depth of cover survey found 91 measurements of 192 (47%) had a depth less than the EGI standard of 0.90 metres and 25 measurements (13%) recorded a depth of less than 0.60 metres (CSA Z662 minimum standard). Poor DOC can lead to increased third-party damages. Additional risk factors include the presence of unrestrained compression couplings, as these create a risk of leak due to frost heave and ground movement and may even pull-out completely as they provide no pull-out retention. CP protection levels over the past 20 years have shown that as much as 37% of the time readings have been below acceptable levels. Poor cathodic protection levels can lead to corrosion.

Assets: NPS 12 ST HP gas main

Related Programs: 6421, 11443

Recommended Alternative Description

Scope of Work: Phase 1 of Martin Grove NPS 12 - HP replacement of approximately 1.2 kilometres of main from Clements Road to Lavington, and replacement of three district stations.

Phase 1: Includes the installation of approximately 1.2 kilometres of NPS 12 HP steel main on Martin Grove Road from Lavington Drive to Clement Road in Etobicoke and the abandonment of approximately 1.2 kilometres of NPS 12 HP steel main along Martin Grove Road. Phase 1 also includes the replacement of three pressure reduction stations and approximately 10 services. The new route will follow Municipal Right of Way and is planned for construction in 2020. The planning and engineering will take place in 2019.

Resources: 2020 - OTC for Phase 1 and resources TBD.

Solution Impact: Main replacement project identified by Asset Management - Pipelines as high-priority. Replacement is required due to age, pipeline condition and risk assessment results.

Project Timing and Execution Risks:
Phase 1 - 2020
Phase 2 - 2024
Risks: moratoriums and easements.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - DP - Main Replacement - Vintage Steel Mains Replacement Program
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	10 - Toronto
	Asset Program (EGI)	DP - Main Replacement
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (6,349,544)	0.00	$ 6,890,651	1/1/2019

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 6,818,951	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ 563,028	$ -	$ -	$ -	$ -

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
10086	**2021**	**5**

Investment Name

NPS 12 Martin Grove Rd - Clements Rd to Lavington

Alternative Value - Recommended

Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(6,350)	100%
Total	**(6,350)**	**100%**

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
11443	2021	5

Investment Name

NPS 12 Martin Grove Rd Main Replacement: Lavington to St. Albans Rd.

Investment Description

Issue/Concern:

General Concerns: Vintage steel mains have shown signs of declining health due to the cumulative effects of poorly manufactured coatings, construction practices, latent third-party damages to pipe coatings, and the effect of stray currents from transit infrastructure (such as the subway and streetcars). The current failure projection model forecasts an exponential increase in the number of corrosion-related failures. The C55 value framework and the 40-year risk projection show an aggressive increase in the safety risk associated with steel main failures. In addition to age, vintage steel mains are also susceptible to accelerated degradation and/or higher risk of third-party damage in the following ways:
- Compression couplings
- Shallow blow-off valve assemblies that could be damaged during excavation activities
- Reduction in the original depth of cover
- Continuous exposure to road salt and seasonal ground movement on bridge crossing assets
- Lack of cathodic protection on pipe casings that could result in corrosion and could lead to the loss of containment
- Manufacturing defects associated with seam welds and fittings that could result in a loss of containment due to prolonged stress and corrosion
- Latent damages to pipe coatings that were never reported to EGI for repair and became active corrosion sites, resulting in accelerated corrosion and potentially loss of containment

Site-specific Concerns:
Martin Grove to St. Albans Road: Address NPS 12 pipe from Lavington Drive South to Burnhamthorpe Road, then west to Ashbourne Drive, then following Auckland Road south to St. Albans Road.

There are over 360 service connections that will be removed from the HP steel main and an intermediate pressure (IP) polyethylene (PE) subsystem installed to reconnect these customers. Depth of cover (DOC) has been identified as a significant concern for these main segments as identified by 2018 and 2019 DOC surveys that found over 52% of the survey locations had DOC less than 90 centimetres, with 77 survey locations measuring less than 60 centimetres of cover. Poor DOC can lead to increased third-party damages. Additional risk factors include two unrestrained compression couplings (CCs), nine restrained CCs, and three suspect valves where due to their installation dates, may have been tied in using unrestrained CCs (as discovered by an Integrity Assessment showing significant correlation between valves of this vintage with unrestrained CC tie-ins).

Cathodic protection history for the past 20 years shows that over 15% of the readings taken each year were below the minimum requirements. Poor cathodic protection levels can lead to corrosion.

Assets: NPS 12 pipe from Lavington Drive south to Burnhamthorpe Road, then west to Ashbourne Drive, then following Auckland Road South to St. Albans Road.

Related Programs: 6421, 10086.

Recommended Alternative Description

Scope of Work: Replacement of approximately 6.4 kilometres of NPS 12 steel main from Martin Grove Road and Lavington Drive South to Burnhmthorpe Road, then west to Ashbourne Drive, then south to Auckland Road and St. Albans Road. Approximately 360 services to be reconnected to a new IP PE sub-system.

Resources: 2024 OTC Phase 2 and resources TBD

Solution Impact: Main replacement project identified by Asset Management - Pipelines as high-priority. Replacement is required due to age, pipeline condition and risk assessment results.

Project Timing and Execution Risks: moratoriums and easements.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - DP - Main Replacement - Vintage Steel Mains Replacement Program
Investment Stage	Short Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	10 - Toronto
	Asset Program (EGI)	DP - Main Replacement
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (13,436,574)	0.00	$ 18,292,755	1/1/2023

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ -	$ -	$ 400,000	$ 17,292,755	$ 600,000
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

ENBRIDGE

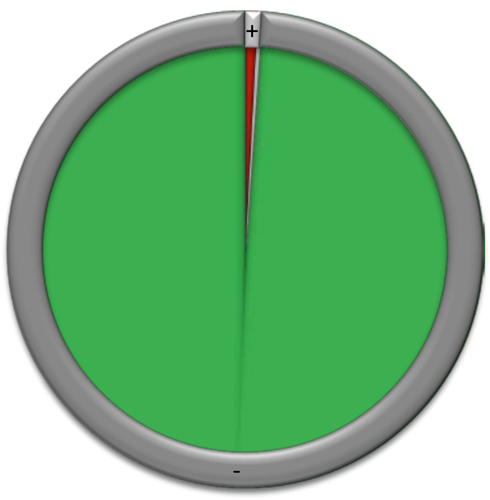
Investment Summary Report

Investment Code	Report Start Year	Number of Years
11443	**2021**	**5**

Investment Name

NPS 12 Martin Grove Rd Main Replacement: Lavington to St. Albans Rd.

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Public Safety Risk	105	1%
Financial Risk	31	0%
Employee And Contractor Safety Risk	11	0%
Reputational Risk	4	0%
Environmental Risk And Remediation	1	0%
Operational Risk	0	0%
Avoided GHG Emissions (CA)	0	0%
Budget Savings OPEX (CA)	0	0%
Cost Avoidance CAPEX (CA)	0	0%
Cost Avoidance OPEX (CA)	0	0%
Total Investment Cost (CA)	(13,437)	99%
Total	**(13,285)**	**100%**

ENBRIDGE **Investment Summary Report**	Investment Code **10293**	Report Start Year **2021**	Number of Years **5**
	Investment Name NPS 12 St. Laurent Aviation Pkwy		

Investment Description

Issue/Concern:
General Concerns: Vintage steel mains have shown signs of declining health due to the cumulative effective of poor manufactured coating performance, construction practices, latent third-party damages to pipe coating, and the effect of stray currents from transit infrastructure such as subway and streetcars. The current failure projection model is forecasting an exponential increase in the number of corrosion-related failures, while the C55 value framework and the 40-year risk projection are showing an aggressive increase in the safety risk associated with steel main failures. In addition to age, vintage steel mains are also susceptible to accelerated degradation and/or higher risk of third party damage in the following ways:
-Compression couplings
-Shallow blow-off valve assemblies that could be damaged during excavation activities
-Reduction in the original depth of cover
-Continuous exposure of road salt and seasonal ground movement on bridge crossing assets
-Lack of cathodic protection with pipe casings that could result in corrosion causing excessive stress or shorts on the carrier pipe that is in contact with the casing, which could lead to the loss of containment
-Manufacturing defects associated with seam welds and fittings that are weak points in the distribution system and could result in a loss of containment due to prolonged exposure to stress and corrosion
-Latent damages to pipe coatings that were never reported to EGI for repair and became active corrosion sites, which could hamper the effect of the corrosion protection system and result in accelerated corrosion and potentially loss of containment.

Site-specific Concerns:
Unable to determine leaks due to the close proximity of the NPS 12 470 psi system. Cathodic protection wasn't installed until the early 1970s. Approximately 429 services are off this network.

This project is to install 8543 metres of 16/12 NPS on Aviation Pkwy tying into the Network 6580 (Ottawa Gate) and running to Rockcliffe Station. And abandon 12 kilometres of NPS 12. Scheduled to be replaced 2022.

Full replacement of main comprising Network 6584 - The NPS 12 St. Laurent Ottawa North line is 13.3 kilometres and operates at 275 psi as Network 6584. It runs from south of St. Laurent Control Station (6584:653:1969) to Rockcliffe Control Station (Station #6B558A). It does not include the main south from St Laurent Control Station to Industrial Ave as well as the NPS 12 lateral main to Trans Alta (6584:1234:1235) but does include the NPS 12 lateral main along Tremblay Road (but does not include the crossing at the Rideau River to Station #61171A).

Assets: Approximately 2.4 kilometres of NPS 16 ST and 6.9 kilometres of NPS 12 Station to be installed and rebuild three stations (Rockcliffe, Birch and St Laurent Control).

Related Programs: 6422, 10089, 10288, 10290, 10291, 10292, 10289, 10294

Recommended Alternative Description

Scope of Work: Install 8268 kilometres of NPS 12, abandon NPS 12, install two new stations and rebuild two stations and rebuild of St Laurent and Rockcliffe Control.

In 2018, pressure increase to Avenue O was completed. In 2019, approx. 3.1 kilometres of plastic pipe was installed on Tremblay and the Avenues and the services transferred over to IP. Also, due to a road moratorium, 2 kilometres of 6" PE IP main on St. Laurent between Donald Street and Montreal needs to be brought forward from 2021 to 2019, as well as approximately 80 services.

In 2021, approximately 8.9 kilometres of plastic pipe will be installed and all the services will be transferred over to IP. Four IP stations will be abandoned and one new station will be installed. Approximately 6.5 kilometres of NPS 1 to 8 will be abandoned. Also, approximately. 0.6 kilometres of 4" SC will be installed to feed four stations that cannot be increased due to the age of the pipe.

In 2022, approximately 12 kilometres of steel pipe will be installed. Rockcliffe, Birch, and St. Laurent Control will be rebuilt, and approximately 9.3 kilometres of NPS 12/16 will be abandoned.

Solution Impact: Replacing the main will ensure the continued operation of EGI's gas distribution system, and will mitigate safety risks to employees, contractors, and general public.

Resources: TBD

Timing and Execution Risks: Phase 4 is to executed in 2022, but the NPS 16/12 cannot be abandoned until this main is installed and all the services have been transferred onto the new IP system.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - DP - Main Replacement - Vintage Steel Mains Replacement Program
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	60 - Ottawa
	Asset Program (EGI)	DP - Main Replacement
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

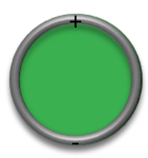
ENBRIDGE **Investment Summary Report**	Investment Code **10293**	Report Start Year **2021**	Number of Years **5**
	Investment Name NPS 12 St. Laurent Aviation Pkwy		

Alternative Spend Profile - Recommended

Name	**Status**	**NPV**	**B/C Ratio**	**Net Base Capex O (CA)**	**Alternative Start Date**
Option 2	Recommended	$ (25,442,683)	0.00	$ 29,787,880	1/1/2019

Account Type	**2021**	**2022**	**2023**	**2024**	**2025**
Base CAPEX O	$ 250,000	$ 27,737,880	$ 1,550,000	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ 4,894,920	$ 450,000	$ -	$ -

Alternative Value - Recommended



Value Function Measure	**Value**	**Value in Percentage**
Total Investment Cost (CA)	(25,443)	100%
Total	**(25,443)**	**100%**

ENBRIDGE Investment Summary Report	Investment Code: 10294	Report Start Year: 2021	Number of Years: 5
	Investment Name: NPS 12 St. Laurent Queen Mary/Prince Albert		

Investment Description

Issue/Concern:

General Concerns: Vintage steel mains have shown signs of declining health due to the cumulative effective of poor manufactured coating performance, construction practices, latent third party damages to pipe coating, and the effect of stray currents from transit infrastructure such as subway and streetcars. The current failure projection model is forecasting an exponential increase in the number of corrosion related failures, while the C55 value framework and the 40-year risk projection are showing an aggressive increase in the safety risk associated with steel main failures. In addition to age, vintage steel mains are also susceptible to accelerated degradation and/or higher risk of third party damage in the following ways:
-Compression couplings
-Shallow blow-off valve assemblies that could be damaged during excavation activities
-Reduction in the original depth of cover
-Continuous exposure of road salt and seasonal ground movement on bridge crossing assets
-Lack of cathodic protection with pipe casings that could result in corrosion causing excessive stress or shorts on the carrier pipe that is in contact with the casing, which could lead to the loss of containment
-Manufacturing defects associated with seam welds and fittings that are weak points in the distribution system and could result in a loss of containment due to prolonged exposure to stress and corrosion
-Latent damages to pipe coatings that were never reported to EGI for repair and became active corrosion sites, which could hamper the effect of the corrosion protection system and result in accelerated corrosion and potentially loss of containment.

Site-specific Concerns: Unable to determine leaks due to the close proximity of the NPS 12 470 psi system. Cathodic protection wasn't installed until the early 1970s. Approximately 429 services are off this network.

Full replacement of main comprising Network 6584 - The NPS 12 St. Laurent Ottawa North line is 13.3 kilometres and operates at 275 psi as Network 6584. It runs from south of St. Laurent Control Station (6584:653:1969) to Rockcliffe Control Station (Station #6B558A). It does not include the main south from St. Laurent Control Station to Industrial Ave as well as the NPS 12 lateral main to Trans Alta (6584:1234:1235) but does include the NPS 12 lateral main along Tremblay Road (but does not include the crossing at the Rideau River to Station #61171A).

In 2018, pressure increase to Avenue O was completed. In 2019, approx. 3.1 kilometres of plastic pipe was installed on Tremblay and the Avenues and the services transferred over to IP. Also, due to a road moratorium, 2 kilometres of 6" PE IP main on St Laurent between Donald Street and Montreal needs to be brought forward from 2021 to 2019 and approximately 80 services.

Assets: (Phase 4) This project is to install 3685 metres of NPS 12 in 2022 and relay 1 service.

Related Programs: 6422, 10089, 10288, 10290, 10291, 10292, 10293, 10289

Recommended Alternative Description

Scope of Work: Install 3780 metres NPS 12, and relay one service.
In 2021, approximately 8.9 kilometres of plastic pipe will be installed and all the services will be transferred over to IP, four IP stations will be abandoned and one new station will be installed. Approximately 6.5 kilometres of NPS 1 to 8 will be abandoned. Also, approx. 0.6 kilometres of 4" SC will be installed to feed four stations that cannot be increased due to the age of the pipe.
In 2022, approx. 12 kilometres of Steel will be installed, Rockcliffe, Birch and St Laurent Control will be rebuilt, and approximately 9.3 kilometres of NPS 12/16 will be abandoned.

Solution Impact: Replacing the main will ensure the continued operation of EGI's gas distribution system, and will mitigate safety risks to employees, contractors, and general public.

Resources: TBD - Bid process

Timing and Execution Risks: Phase 4 is to executed in 2022, but the NPS 16/12 cannot be abandoned until this main is installed and all the services have been transferred onto the new IP system.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - DP - Main Replacement - Vintage Steel Mains Replacement Program
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	60 - Ottawa
	Asset Program (EGI)	DP - Main Replacement
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

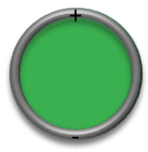
Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 2	Recommended	$ (9,448,268)	0.00	$ 11,050,071	1/1/2019

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 100,000	$ 10,340,071	$ 530,000	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ 1,824,718	$ 180,000	$ -	$ -

ENBRIDGE **Investment Summary Report**	Investment Code **10294**	Report Start Year **2021**	Number of Years **5**
	Investment Name NPS 12 St. Laurent Queen Mary/Prince Albert		

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(9,448)	100%
Total	**(9,448)**	**100%**

Enbridge **Investment Summary Report**	Investment Code **10088**	Report Start Year **2021**	Number of Years **5**
	Investment Name NPS 20 Lake Shore Replacement (Cherry to Bathurst)		

Investment Description

Issue/Concern:

General Concerns:
Vintage steel mains have shown signs of declining health due to the cumulative effects of poorly manufactured coatings, construction practices, latent third-party damages to pipe coatings and the effect of stray currents from transit infrastructure (such as the subway and streetcars). The current failure projection model forecasts an exponential increase in the number of corrosion-related failures.
In addition to age, vintage steel mains are also susceptible to accelerated degradation and/or higher risk of third-party damage in the following ways:
- Compression couplings
- Shallow blow-off valve assemblies that could be damaged during excavation activities
- Reduction in the original depth of cover
- Continuous exposure to road salt and seasonal ground movement on bridge crossing assets
- Lack of cathodic protection on pipe casings that could result in corrosion and lead to the loss of containment
- Manufacturing defects on seam welds and fittings that could result in leaks due to prolonged stress and corrosion
- Latent damages to pipe coatings that were never reported to EGI for repair and became active corrosion sites, resulting in accelerated corrosion and potentially loss of containment

Site-specific Concerns:
The NPS 20 Lake Shore Replacement project from Cherry Street to Bathurst Street addresses vintage steel mains installed in 1954. This project was assessed using Asset Health Review methodology, the C55 value framework, tacit knowledge from internal stakeholders and in-line inspection (ILI)/Integrity dig results. In addition to the declining health demonstrated by vintage steel mains, this pipeline is part of the KOL system in the Toronto area, known to have a number of features that make it more susceptible to accelerated degradation and/or higher risk of third-party damage. These features include but are not limited to:
- Compression couplings on mains and services
- Reduced depth of cover
- Shallow blow-off valves
- Lack of cathodic protection
- Live stubs
- Stray current from hydro infrastructure
- Possibly contaminated soils

In 2016 and 2018, inline inspections (ILI) using a robotic crawler were performed on approximately 1.9 kilometres of the 4.5 kilometres of pipe selected for Phase 1. The 2016 ILI survey found 2 areas that required immediate rehabilitation activities via 2 Integrity digs. There are an additional six Integrity digs recommended over the next 10 years. The 2018 inspection identified 24 further dig locations that would require Integrity remediation over the next 10 years as per the guidance from CSA Z662. These digs are required to mitigate the corrosion and dent features that could exhibit more than 80% wall loss or have a high probability of failure, representing significant degradation of the pipe. Costs for such Integrity digs, based on the integrity digs in 2017 and 2018, range from $350,000 to $450,000 per integrity dig. This implies that over the next 10 years EGI could be expected to spend $10,500,000 to $13,500,000 to rehabilitate these 30 locations, leaving the remaining pipe as bad as old. These Integrity digs would also require multiple construction zone impacts to the local traffic and businesses in a highly congested area of downtown Toronto. The multiple interruptions would have a negative impact to the reputation of safe and reliable service for EGI. Furthermore, the ILI survey also indicated another 10 features that may require mitigation activity within 15 years ($3.5M~$4.5M additional spend), which is an indication that the pipe is reaching the end of its safe and reliable service life and that a repair approach is not a sustainable approach.

Recommended Alternative Description

Scope of Work: This project is a size-for-size replacement of the existing NPS 20 HP steel main on Lake Shore Blvd from Cherry Street to Bathurst Street. This work includes approximately 4850 metres of NPS 20 and 500 metres of NPS 20 on Mill Street, it runs on Lake Shore Boulevard from Parliament Street to Bathurst Street.

Resources: 2021 - OTC and would be bid on by external contractors

Solution Impact: Main replacement project identified by Asset Management - Pipelines as high-priority. Replacement is required due to age, pipeline condition and risk assessment results. Further investigation was completed in 2018 to collect additional pipe condition data to assist in the planning, engineering and risk components. This confirmed the timing for execution of this replacement project for 2021.

Project Timing and Execution Risks: Moratoriums, third-party developments, Gardiner realignment and required easements.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - DP - Main Replacement - Vintage Steel Mains Replacement Program
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	10 - Toronto
	Asset Program (EGI)	DP - Main Replacement
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Investment Summary Report

Investment Code	Report Start Year	Number of Years
10088	2021	5

Investment Name

NPS 20 Lake Shore Replacement (Cherry to Bathurst)

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (94,067,357)	0.00	$ 104,689,659	1/1/2019

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 64,118,854	$ 39,315,232	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ 2,000,000	$ -	$ -	$ -

Alternative Value - Recommended

Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(94,067)	100%
Total	**(94,067)**	**100%**

Investment Summary Report	Investment Code	Report Start Year	Number of Years
	17365	2021	5
	Investment Name: NPS 8 Eagleson Rd (Kanata) Retrofit for ILI		

Investment Description

Issue/Concern:
An Area 60 pipeline was identified to be operating at a Maximum Operating Pressure (MOP) above the threshold for integrity mains (operating above 29.5% SMYS) by the MOP team. The pipeline is identified as NPS 8 Eagleson Road (Kanata) that is operating at 470 PSI which corresponds to 30.8% SMYS. The current operating set pressure for the pipeline as acquired from Source Records 2016/2017 is 400 PSI, corresponding to 30.4% of pipe material SMYS, which means that the pipeline needs to be included in the Integrity Management Program, according to TSSA CAD, FS-220-16, Clause 10.3.11.

General: The Integrity Retrofit portion of the Integrity Management Program is to specifically capture retrofit work to make pipelines inline inspectable. The Integrity Management Program is a mandated regulatory requirement which has been designed to comply with all applicable codes and standards. The program consists of the regular assessment and maintenance of the integrity of pipeline systems at EGI to ensure their continued safety and reliability. Most of the expenditure included in this category is for pipelines that operate above 30% SMYS. It includes installation costs for permanent in-line inspection (ILI) tool launcher and receiver facilities, retrofits to existing lines to remove restrictive fittings or pipe configurations so they can be inspected with ILI tools, and remediation of pipeline segments with integrity issues that are identified through the inspections.

Assets: Network #6581

Related Programs: N/A

Recommended Alternative Description

Scope of Work:
The specific scope of work involves: Installation of temporary launcher and receiver; replace a mixture of NPS 6 and 8 main with NPS 8 main; NPS 6 kerotest valve cutouts and installation of piggable valves; LSF cutout and installation of piggable fittings.

Solution Impact: Execution will allow for the safe inspection of the IMP main as per EGI's Integrity Management Program.

Resources: Engineering Construction, TFS and EGI Contractor.

Timing and Execution Risks: This project is scheduled for Fall 2020 and Spring/Summer 2021.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - DP - Integrity - Integrity Retrofit
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	60 - Ottawa
	Asset Program (EGI)	DP - Integrity
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	Yes
	Compliance Justification & Code	The Integrity retrofits portion of the Integrity Management Program is to specifically capture work to retrofit pipelines for inline inspection (ILI). It includes installation costs for permanent ILI tool launcher and receiver facilities, retrofits to existing lines to remove restrictive fittings or pipe configurations, and the retrofit of some pipelines that were initially assessed through ECDA to accommodate ILI tools and improve the completeness of the integrity assessments. The Integrity Management Program is a mandated regulatory requirement which has been designed to comply with all applicable codes and standards.
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Retrofit	Recommended	$ (4,145,778)	0.00	$ 4,357,440	1/1/2019

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 2,857,440	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended

Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(4,146)	100%
Total	**(4,146)**	**100%**

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
12268	2021	5

Investment Name

NPS 8 East Valley - Lancaster to Alexandria Pipeline - Retrofit/Replacement

Investment Description

Issue/Concern/Opportunity: This retrofit project will allow in-line inspection of the pipeline which is required as per the Integrity Management Program.

General: The Integrity Retrofit portion of the Integrity Management Program is to specifically capture retrofit work to make pipelines inline inspectable. The Integrity Management Program is a mandated regulatory requirement which has been designed to comply with all applicable codes and standards. The program consists of the regular assessment and maintenance of the integrity of pipeline systems at EGI to ensure their continued safety and reliability. Most of the expenditure included in this category is for pipelines that operate above 30% SMYS. It includes installation costs for permanent in-line inspection (ILI) tool launcher and receiver facilities, retrofits to existing lines to remove restrictive fittings or pipe configurations so they can be inspected with ILI tools, and remediation of pipeline segments with integrity issues that are identified through the inspections.

Assets: Network 6587 NPS 8 East Valley line.

Related Programs: N/A

Recommended Alternative Description

Scope of Work:
Installation of permanent launcher and receiver. Retrofit nine locations containing unpiggable fittings (LSFs, undersized valves, and reduced port flange) with full port piggable fittings.

Solution Impact: Execution will allow for the safe inspection of the IMP main as per EGI's Integrity Management Program.

Resources: Engineering Construction, TFS and EGI contractor

Timing and Execution Risks: This project is scheduled for Fall 2020 and Spring/Summer 2021.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - DP - Integrity - Integrity Retrofit
Investment Stage	Executing		

Investment Overview

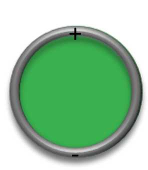
1. Project Information	State/Province	Ontario
	Operating Area (EGI)	60 - Ottawa
	Asset Program (EGI)	DP - Integrity
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	Yes
	Compliance Justification & Code	This project is part of the Gas Storage and Transmission System (GSTS) Integrity management plan that satisfies the requirements of the Pipeline Integrity Management Program mandated by CSA Z662-15 clause 3.2 and 10.3.10 as audited by the TSSA. The pipeline project is compliance driven and must be completed as part of the IMP.
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Retrofit Line for ILI	Recommended	$ (3,148,967)	0.00	$ 3,242,364	1/1/2018

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 1,260,864	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(3,149)	100%
Total	**(3,149)**	**100%**

Investment Code	Report Start Year	Number of Years
10290	2021	5

ENBRIDGE

Investment Summary Report

Investment Name

St. Laurent Plastic - Coventry/Cummings/St Laurent

Issue/Concern:

General Concerns: Vintage steel mains have shown signs of declining health due to the cumulative effective of poor manufactured coating performance, construction practices, latent third party damages to pipe coating, and the effect of stray currents from transit infrastructure such as subway and streetcars. The current failure projection model is forecasting an exponential increase in the number of corrosion related failures, while the C55 value framework and the 40-year risk projection are showing an aggressive increase in the safety risk associated with steel main failures. In addition to age, vintage steel mains are also susceptible to accelerated degradation and/or higher risk of third party damage in the following ways:
-Compression couplings
-Shallow blow-off valve assemblies that could be damaged during excavation activities
-Reduction in the original depth of cover
-Continuous exposure of road salt and seasonal ground movement on bridge crossing assets
-Lack of cathodic protection with pipe casings that could result in corrosion, causing excessive stress or shorts on the carrier pipe that is in contact with the casing, which could lead to the loss of containment
-Manufacturing defects associated with seam welds and fittings that are weak points in the distribution system and could result in a loss of containment due to prolonged exposure to stress and corrosion
-Latent damages to pipe coatings that were never reported to EGI for repair and became active corrosion sites, which could hamper the effect of the corrosion protection system and result in accelerated corrosion and potentially loss of containment.

Site-specific Concerns: Unable to determine leaks due to the close proximity of the NPS 12 470 psi system. Cathodic protection wasn't installed until the early 1970s. Approximately 429 services are off this network.
Full replacement of main comprising Network 6584 - The NPS 12 St. Laurent Ottawa North line is 13.3 kilometres and operates at 275 psi as Network 6584. It runs from south of St. Laurent Control Station (6584:653:1969) to Rockcliffe Control Station (Station #6B558A). It does not include the main south from St. Laurent Control Station to Industrial Avenue as well as the NPS 12 lateral main to Trans Alta (6584:1234:1235) but does include the NPS 12 lateral main along Tremblay Road (but does not include the crossing at the Rideau River to Station #61171A).

In 2018, pressure increase to Avenue O was completed. In 2019/2020, approximately 3.1 kilometres of plastic pipe has been installed on Tremblay and the Avenues and the services transferred over to IP. Due to a road moratorium, 2 kilometres of 6" PE IP main on St. Laurent between Donald Street and Montreal was brought forward from 2021 to 2019/2020 and approximately 80 services.

Assets: This project is to install 800 metres NPS 6, 525 metres NPS 2 IP, transfer 27 services to IP from XHP, abandon one station on Coventry and Cummings.

Related Programs: 6422, 10089, 10288, 10289, 10291, 10292, 10293, 10294

Recommended Alternative Description

Scope of Work: Install 800 metres of NPS 6 and 525 metres of NPS 2 pipe, transfer 27 customers to IP. Abandon one station.

Solution Impact: Replacing the main will ensure the continued operation of EGI's gas distribution system, and will mitigate safety risks to employees, contractors, and general public.

Resources: OTC 2021/22 - Resources TBD

Timing and Execution Risks: Scheduled for execution in 2021, but will need to balance this work with regional resourcing to achieve in 2021.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - DP - Main Replacement - Vintage Plastic Replacement Program
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	60 - Ottawa
	Asset Program (EGI)	DP - Main Replacement
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (3,322,128)	0.00	$ 3,677,958	1/1/2019

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 2,581,554	$ 1,081,020	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ 519,750	$ 360,672	$ -	$ -	$ -

Investment Summary Report	Investment Code	Report Start Year	Number of Years
	10290	2021	5
	Investment Name		
	St. Laurent Plastic - Coventry/Cummings/St Laurent		

Alternative Value - Recommended

Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(3,322)	100%
Total	**(3,322)**	**100%**

Investment Summary Report	Investment Code	Report Start Year	Number of Years
	10288	2021	5
	Investment Name: St. Laurent Plastic - Lower Section		

Investment Description

Issue/Concern:

General Concerns: Vintage steel mains have shown signs of declining health due to the cumulative effective of poor manufactured coating performance, construction practices, latent third-party damages to pipe coating and the effect of stray currents from transit infrastructure such as subway and streetcars. The current failure projection model is forecasting an exponential increase in the number of corrosion related failures, while the C55 value framework and the 40-year risk projection are showing an aggressive increase in the safety risk associated with steel main failures.

In addition to age, vintage steel mains are also susceptible to accelerated degradation and/or higher risk of third party damage in the following ways:
-Compression couplings
-Shallow blow-off valve assemblies that could be damaged during excavation activities
-Reduction in the original depth of cover
-Continuous exposure of road salt and seasonal ground movement on bridge crossing assets
-Lack of cathodic protection with pipe casings that could result in corrosion causing excessive stress or shorts on the carrier pipe that is in contact with the casing, which could lead to the loss of containment
-Manufacturing defects associated with seam welds and fittings that are weak points in the distribution system and could result in a loss of containment due to prolonged exposure to stress and corrosion
-Latent damages to pipe coatings that were never reported to EGI for repair and became active corrosion sites, which could hamper the effect of the corrosion protection system and result in accelerated corrosion and potentially loss of containment.

Site-specific Concerns:
Unable to determine leaks due to the close proximity of the NPS 12 470 psi system. Cathodic protection wasn't installed until the early 1970s. Approximately 429 services are off this network. Full replacement of main comprising Network 6584 - The NPS 12 St. Laurent Ottawa North line is 13.3 kilometres and operates at 275 psi as Network 6584. It runs from south of St. Laurent Control Station (6584:653:1969) to Rockcliffe Control Station (Station #6B558A). It does not include the main south from St. Laurent Control Station to Industrial Avenue as well as the NPS 12 lateral main to Trans Alta (6584:1234:1235) but does include the NPS 12 lateral main along Tremblay Road (but does not include the crossing at the Rideau River to Station #61171A).

In 2018, pressure increase to Avenue O was completed. In 2019/2020, approximately 3.1 kilometres of plastic pipe has been installed on Tremblay and the Avenues and the services transferred over to IP. Due to a road moratorium, 2 kilometres of 6" PE IP main on St. Laurent between Donald Street and Montreal was brought forward from 2021 to 2019/2020 and approximately 80 services.

Assets: Lower Section is comprised of 2 projects:
Lower Section Part 1: Lancaster and Gladwin Cres Install 1.9 kilometres of 4" PE relaying 17 services, eight headers and pressure increasing two headers and relighting 170 customers
Lower Section Part 2: Industrial Avenue Install 1.3 kilometres of 4" PE and relay 13 services and pressure increase 2 headers and relight approximately 44 customers

Related Programs: 6422, 10089, 10289, 10290, 10291, 10292, 10293, 10294

Recommended Alternative Description

Scope of Work: Install 2924 metres of NPS 4, abandon 2970.6 metres of SC, transfer 126 connections to IP.

In 2021, Install approximately 1.1 kilometres of NPS 4 IP PE on St. Laurent Blvd and Industrial Avenue Street transferring 44 customers to IP. Abandon approximately 565 metres of 4 SC and 371 metres of 12 higher-pressure pipe. Tie-in to 6544 at Bourassa Street and St. Laurent Boulevard a 55# IP system and Russell Road and Industrial Avenue making this a two-way feed.

Solution Impact: Replacing the main will ensure the continued operation of EGI's gas distribution system, and will mitigate safety risks to employees, contractors, and general public.

Resources: Regional Construction and Engineering Construction (if there is no capacity from Regional Construction).

Timing and Execution Risks: To be executed in 2021, will need to work with region to ensure resourcing so this is achievable.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - DP - Main Replacement - Vintage Plastic Replacement Program
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	60 - Ottawa
	Asset Program (EGI)	DP - Main Replacement
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (4,152,951)	0.00	$ 4,512,874	1/1/2019

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 4,289,202	$ 200,000	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ 68,843	$ -	$ -	$ -	$ -

ENBRIDGE Investment Summary Report	Investment Code	Report Start Year	Number of Years
	10288	**2021**	**5**
	Investment Name		
	St. Laurent Plastic - Lower Section		

Alternative Value - Recommended

	Value Function Measure	Value	Value in Percentage
	Total Investment Cost (CA)	(4,153)	100%
	Total	**(4,153)**	**100%**

ENBRIDGE **Investment Summary Report**	Investment Code **10292**	Report Start Year **2021**	Number of Years **5**
	Investment Name St. Laurent Plastic (Montreal to Rockcliffe)		

Investment Description

Issue/Concern:
General Concerns: Vintage steel mains have shown signs of declining health due to the cumulative effective of poor manufactured coating performance, construction practices, latent third-party damages to pipe coating, and the effect of stray currents from transit infrastructure such as subway and streetcars. The current failure projection model is forecasting an exponential increase in the number of corrosion related failures, while the C55 value framework and the 40-year risk projection show an aggressive increase in the safety risk associated with steel main failures. In addition to age, vintage steel mains are also susceptible to accelerated degradation and/or higher risk of third party damage in the following ways:
-Compression couplings
-Shallow blow-off valve assemblies that could be damaged during excavation activities
-Reduction in the original depth of cover
-Continuous exposure of road salt and seasonal ground movement on bridge crossing assets
-Lack of cathodic protection with pipe casings that could result in corrosion causing excessive stress or shorts on the carrier pipe that is in contact with the casing, which could lead to the loss of containment
-Manufacturing defects associated with seam welds and fittings that are weak points in the distribution system and could result in a loss of containment due to prolonged exposure to stress and corrosion
-Latent damages to pipe coatings that were never reported to EGI for repair and became active corrosion sites, which could hamper the effect of the corrosion protection system and result in accelerated corrosion and potentially loss of containment.

Site-specific Concerns:
Unable to determine leaks due to the close proximity of the NPS 12 470 psi system. Cathodic protection was not installed until the early 1970s. Approximately 429 services are off this network.

Full replacement of main comprising Network 6584 - The NPS 12 St. Laurent Ottawa North line is 13.3 kilometres and operates at 275 psi as Network 6584. It runs from south of St. Laurent Control Station (6584:653:1969) to Rockcliffe Control Station (Station #6B558A). It does not include the main south from St Laurent Control Station to Industrial Avenue as well as the NPS 12 lateral main to Trans Alta (6584:1234:1235) but does include the NPS 12 lateral main along Tremblay Road (but does not include the crossing at the Rideau River to Station #61171A).

In 2018, pressure increase to Avenue O was completed. In 2019/2020, approximately 3.1 kilometres of plastic pipe has been installed on Tremblay and the Avenues and the services transferred over to IP. Due to a road moratorium, 2 kilometres of 6" PE IP main on St. Laurent between Donald Street and Montreal was brought forward from 2021 to 2019/2020 and approximately 80 services.

Assets: Install approx. 2.9 kilometres of 6" PE and 122 metres of 2" PE, transfering 135 customers to the IP, pressure decrease Hillsdale Rd and abandon St 6B882 Lansdowne/Hillsdale.

Related Programs: 6422, 10089, 10288, 10290, 10291, 10289, 10293, 10294

Recommended Alternative Description

Scope of Work: Install 3385 NPS 6, 445 NPS 4 and 348 NPS 2, transfer 123 connections to IP. Abandon eight stations and install one new station.

In 2021, approximately 8.9 kilometres of plastic pipe will be installed and all the services will be transferred over to IP, four IP stations will be abandoned and one new station will be installed. Approximately 6.5 kilometres of NPS 1 to 8 will be abandoned. Approximately 0.6 kilometres of 4" SC will be installed to feed four stations that cannot be increased due to the age of the pipe.

In 2022, approximately 12 kilometres of steel pipe will be installed. Rockcliffe, Birch and St. Laurent Control will be rebuilt, and approximately 9.3 kilometres of NPS 12/16 will be abandoned. This project tasks are:
- Install three kilometres NPS 6, 445 metres of NPS 4 and 300 metres of NPS 2 IP.
- Transfer 123 services to IP.
- Abandon one station on St. Laurent and Sandridge from Montreal to Rockcliffe Station.

Solution Impact: Replacing the main will ensure the continued operation of EGI's gas distribution system, and will mitigate safety risks to employees, contractors, and general public.

Resources: Regional Construction and Engineering Construction if there is no capacity from Regional Construction.

Timing and Execution Risks: Phase 3 is to executed in 2021, but due to the volume of work for the region this may not be achieved in 2021.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - DP - Main Replacement - Vintage Plastic Replacement Program
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	60 - Ottawa
	Asset Program (EGI)	DP - Main Replacement
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Investment Summary Report

Investment Code	Report Start Year	Number of Years
10292	2021	5

Investment Name

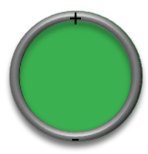
St. Laurent Plastic (Montreal to Rockcliffe)

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (3,882,224)	0.00	$ 4,248,935	1/1/2019

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 3,582,985	$ 652,770	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ 195,750	$ 313,347	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(3,882)	100%
Total	**(3,882)**	**100%**

Distribution Stations

Investment Summary Report	Investment Code	Report Start Year	Number of Years
	7061	**2021**	**5**
	Investment Name		
	Brampton Gate Station Rebuild		

Investment Description

Issue/Concern:
The Brampton gate station has the following issues by subsystem:

Pipe, Valves and Others: No identified issues, but will be reconfigured to accommodate the rebuild. Upgrade to Station Inlet piping to accommodate a new horizontal gas separatos filters to prevent any liquids from the NEB 24 inlet from entering the station

Heating System: The heating system is in a hazardous area and must be moved. In addition, it has an obsolete control system that is no longer supported.

Pressure Control: One of the pressure control runs has a Kerotest inlet valve that is low to grade. There are concerns about the water table in the station and a redesign will address the issues. A Becker regulator will need to be added to provide remote control for the NPS 12 line - Network 2187.

Oduorant System: The odourant building does not include the injection panel and does not have complete containment if the injection panel has a rupture.

Telemetry/Electrical: The telemetry and electrical systems will be brought up to current standards and may include methane and CO sensors and monitoring, station wiring upgrades, electrical service upgrades, station grounding, telemetry tower upgrades, UPS installation, generator or TEG upgrades, modem and firewall upgrades, station lighting upgrades, weather station installation/replacement, and gas chromatograph installation. New generator to be installed, current generator is at end-of-life. Additional Control Tuning requirements needed for Network 2187 outlet NPS 12. This will include addition of DNGP controllers and associated Telemetry equipment within the new RTU Building.

Measurement: Existing turbine meter will be replaced.

Compliance/Civil: Site grading will be required. Recoat all above ground piping and fittings including fittings, station filter, etc. Insulation of new heating system inlet (boiler building or cold weather technologies) Remove existing east fence line. Move existing east fence line to align with TCPL fence. Replace south fence to replace gap in fence between EGI and TCPL. Remove tree on west end side of property (climbing hazard).

Assets: Station# 20101A, 20101B, 20101C

Related Program(s): N/A

Recommended Alternative Description

Scope Work:
Pipes and Valves: Excessive station piping will be shortened and/or removed.

Heating System: The obsolete Delta V controller will be replaced with new Honeywell controllers. The boiler building will also be relocated to an area outside of any hazardous areas. Install new CWT or conventional boiler System (new building, if required). New inlet/outlet piping including valves required. Remove existing boiler building and associated mechanical piping assets.

Pressure Control: The existing double boot style regulators will be replaced with new regulators sized to handle the future projected load. Replace Run 1 to table top design to remove run from water table (STN #20101A) Replace Run 2 to table top design to remove run from water table (STN #20101B) Upgrade STN #20101C due to Kerotest inlet valve to be raised.

Odourant System: The entire odourant system will be replaced with a new system meeting design standards. The new odourant building will contain both the tank and injection panel, complete with containment, fire suppression system, and CGI's. New odourant building required. This will include the removal of the existing “dog shed” building to make room for the new building.

Telemetry and Electrical: Remove existing RTU/Electrical Building. Install NEW RTU/Electrical Building (Repurpose existing RTU Equipment). Relocate new generator to location next to new RTU/electrical building. Remove expansion tank and generator pad. Relocate incoming power from Brampton Hydro authority. New electrical/telemetry connection for E+H Meter. New electrical/telemetry connection for micromotion meter. Upgrade all meter-run pipe Supports. Relocate all pressure and temperature transmitters to pipeline (x5). Account for new telemetry tower location.

Measurement: The existing turbine meter will be replaced with mass-flow meters.

Solution Impact: Rebuilding the station location will mitigate safety risks to employees, contractors, and the general public.

Resources: Company crews, contractor labour and third-party vendor suppliers

Project Timing and Execution Risk: Planning in Year 1, Execution in Year 2. Execution Risk - Weather impacts, resource availability, procurement issues, etc.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - Distribution Stations - Gate, Feeder & A Stations
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	20 - Mississauga
	Asset Program (EGI)	DS - Gate, Feeder & A Stations
	Asset Class (EGI)	Distribution Stations
2. Compliance	Compliance Investment	Yes
	Compliance Justification & Code	RTU Building in Hazardous Area, Boiler Building in Hazardous Area, Containment on odourant. Canadian Electrical Code Section 22.1
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Investment Summary Report

Investment Code	Report Start Year	Number of Years
7061	2021	5

Investment Name

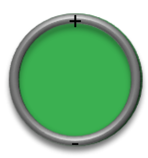
Brampton Gate Station Rebuild

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (2,362,000)	0.00	$ 2,547,760	1/1/2020

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 2,507,760	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ 12,500	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(2,362)	100%
Total	**(2,362)**	**100%**

Investment Summary Report	Investment Code	Report Start Year	Number of Years
	3609	2021	5
	Investment Name: CONSUMERS RD		

Investment Description

The Consumers Road Feeder station has heating concerns (to be addressed in 2020), piping and pressure control issues. Further information is described below for each sub-asset system.

Pipe, Valves and Others: The piping configuration has two different maximum operating pressures (MOP) that are not isolated by two valves and could potentially limit the operability of the station. In addition, the gas filter capacity is not sufficient and requires an upgrade.

Heating System: Not Required (being addressed in 2020)

Pressure Control and Odourant System: Not Required

Telemetry/Electrical: Not Required (being addressed in 2020)

Building: Removal of existing regulator building as Becker control valves will be designed below grade

Compliance/Civil: Fence replacement may need to be required. REWS to be consulted.

This project has high costs related to the turbo expander/fuel cell and piping configuration. The property has spacing issues that make the execution of the project difficult. The 2020 spend is primarily for the heating equipment (outsourced design and prefabrication).

Assets: Station #10471A

Related Program(s): N/A

Recommended Alternative Description

Scope of Work:
The station will be rebuilt in a phased approach (started in 2019).
- Pipe, Valves and Others: Replace inlet and out station valves (NPS 12 inlet) and (NPS 16 outlet) and station bypass valve (NPS 12). To execute the filter and inlet/outlet valve replacement will require tapping and stopping procedures outside of the station to isolate the flow of gas through the station.
- Replace the turbo expander components (Blade, etc.) utilizing the maintenance package (currently en-route from California, USA)
- Roof cover for the Hydro switch gear transfer building
- Roof cover for power cable tray from switch gear building to main electrical building (7 feet in length)
- Address Gear Body of Valve #33381
- Relocation + New Building for Boiler System (Potentially double the size of current building – x2 – 1 Million BTU System). This design will be a prefabricated system that will cost more upfront but will save execution resources on site.
- Proposed x3 Boiler System (x3 – 2 Million BTU Boilers)
- Annubar bar measurement + spool (designed by Lakeside)
- Relocation of the thermo sensor location (does not provide differential reading)
- Proposed + new building for RTU equipment due to heat issues within the current boiler build removal of fuel cell unit:
- Full removal of all fuel cell components
- Removal of power cable tray back to EGI electrical building including Tek cables into main disconnect equipment
- Removal of concrete pad
- Removal of glycol lines
- Draining of glycol fluid
- Upsize inlet and out isolation control valves (NPS 8 inlet) and (NPS 12 outlet).
- Install new monitor and operator (Qty. 6) (below-grade Becker control valves). Fiberglass huts will require Becker control valves.
- New design to include three monitor and operator.
- Abandonment of existing glycol lines if not captured in 2020.

Solution Impact: Rebuilding the station will mitigate safety risks to employees, contractors and the general public.

Resources: Company crews, contractor labour and third-party vendor suppliers.

Project Timing and Execution Risk: Heating system in 2020 and balance of scope in 2021. Execution Risk - weather impacts, resource availability, procurement, etc.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - Distribution Stations - Gate, Feeder & A Stations
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	10 - Toronto
	Asset Program (EGI)	DS - Gate, Feeder & A Stations
	Asset Class (EGI)	Distribution Stations
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

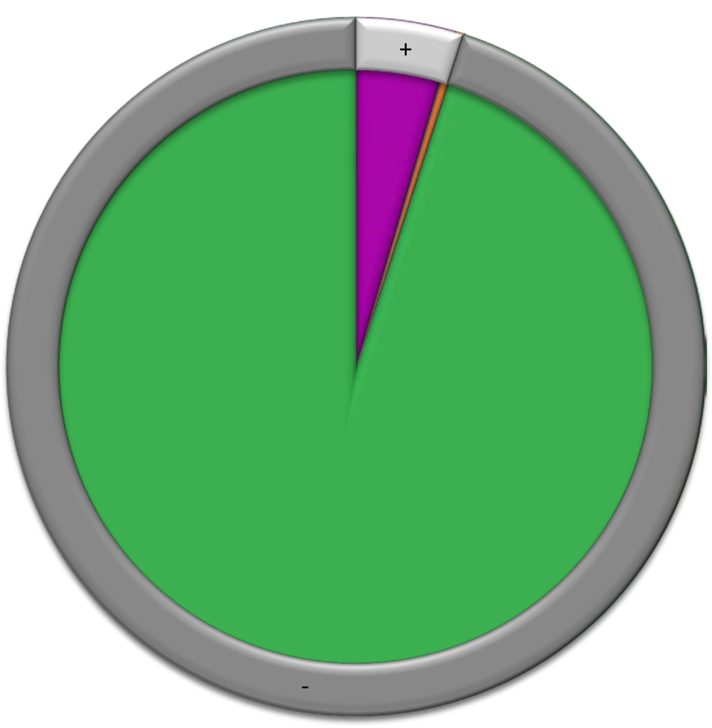
	Investment Code	Report Start Year	Number of Years
Investment Summary Report	3609	2021	5
	Investment Name		
	CONSUMERS RD		

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (4,141,564)	0.00	$ 6,444,604	1/1/2018

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 4,110,865	$ 413,616	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ 82,500	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Financial Risk	199	5%
Cost Avoidance OPEX (CA)	19	0%
Public Safety Risk	0	0%
Avoided GHG Emissions (CA)	0	0%
Budget Savings CAPEX (CA)	0	0%
Budget Savings OPEX (CA)	0	0%
Cost Avoidance CAPEX (CA)	0	0%
Employee And Contractor Safety Risk	0	0%
Energy Efficiency (CA)	0	0%
Environmental Risk And Remediation	0	0%
Gas Storage Reliability (CA)	0	0%
Operational Risk	0	0%
Reputational Risk	0	0%
Revenue Impact (CA)	0	0%
Operational Disruption Risk (Gas) (CA)	0	0%
Operational Disruption Risk (Liquids) (CA)	0	0%
Total Investment Cost (CA)	(4,161)	95%
Total	**(3,943)**	**100%**

Investment Summary Report	Investment Code	Report Start Year	Number of Years
	3455	2021	5
	Investment Name: Harmer District Station		

Investment Description

Issue/Concern: EGI has an HP to IP district station located inside a building. The regulator station is located in the garage of a house and is not to current EGI standards. The station is located close to a school, hospital, shopping complex and dense residential population. The Integrity team is planning an in-line inspection of the Vital NPS 12 main (Network 6582) and additional space is required for a receiver.

Assets: Station# 6B005A

Related Program(s): N/A

Recommended Alternative Description

Scope of Work: Relocate Harmer District Station to Tunney's Pasture and complete rebuild as part of a system reinforcement. System reinforcement required for customer load increase request at Cliff Street and potentially required for future development at Tunney's Pasture.

Solution Impact: Relocating the station location will mitigate safety risks to employees, contractors and the general public.

Resources: Company crews, contractor labour and third-party vendor suppliers

Project Timing and Execution Risk: Planning in Year 1, Execution in Year 2 / Execution Risk - Weather impacts, resource availability, procurement issues, etc.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - DS - Station Rebuilds & B and C Stations - General Station Rebuilds
Investment Stage	Short Term Planning		

Investment Overview

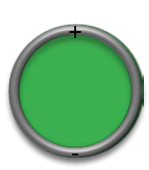
1. Project Information	State/Province	Ontario
	Operating Area (EGI)	60 - Ottawa
	Asset Program (EGI)	DS - Station Rebuilds & B and C Stations
	Asset Class (EGI)	Distribution Stations
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (11,213,073)	0.00	$ 13,078,928	1/1/2022

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ -	$ 13,078,928	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ 871,929	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(11,213)	100%
Total	**(11,213)**	**100%**

ENBRIDGE Investment Summary Report	Investment Code **8567**	Report Start Year **2021**	Number of Years **5**
	Investment Name STJOHN SIDEROAD FEEDER		

Investment Description

Issue/Concern: The property on which St. John's Sideroad feeder station currently sits is insufficient for operation. It is located adjacent to a residential property and the area classification extends onto the adjacent private property. The boiler building is located in a hazardous area classification and the non-compliance needs to be remedied. Road widening of St. John's Sideroad currently has the sidewalk encroaching on our station. A land sale agreement with York Region was completed in 2016 and requires movement of the electrical meter.

As the area classification issue risks shutdown of the station by the Electrical Safety Authority, EGI is planning to resolve the movement of the electrical meter (on site) pending a new land purchase for relocation of the entire station. As a result of station relocation, a complete rebuild will be required. Maintenance on the boiler system piping, pumps and gauges, which are old and obsolete, suggest that the heating system needs to be replaced regardless of station relocation. The heating system is already undersized for the current demand. The FL regulators are difficult to work on due to their weight and ergonomic restrictions in a cramped building. These are to be replaced and upgraded. The old RTU 3330 telemetry system needs to be upgraded, including the backup power generator which is old and obsolete. The station was updated in 2006 and a new generator and boilers were installed in 2003. Source records do not indicate any regulator capacity issue .

Asset: Stn ID: 2944180

Related Programs: N/A

Recommended Alternative Description

SCOPE OF WORK:
2020 spend focused on land purchase. Reduced to $100k based on a deposit for preferred property location. If successful, property deal would close in 2020 for $1.1M. Uncertainty remains if the landowner will accept our offer to sell.
A new station and all supporting infrastructure will be constructed on a newly acquired parcel of land. The existing station will be removed from service and abandoned appropriately.
The new location will be in close proximity to the existing station just off of St. John's Sideroad, East of Leslie Street and west of Highway 404.
Pipes and Valves: All existing piping will have to be built as part of the station relocation. This includes station isolation and bypass valves as well as isolation valves required for the heating system and regulator runs. A new fuel gas station will be required that includes measurement of fuel gas consumption by the boilers and the generator.
Heating System: A new boiler and heat exchanger type heating system will have to be installed for gas preheat and all area classification requirements will be met.
Pressure Control: New regulator runs will have to be installed as the existing FL regulators are difficult to maintain.
Odourant System: No odourant system is required as this is a feeder station.
Telemetry and Electrical: The existing RTU panel will be replaced with a new unit in a new electrical building to meet area classification requirements. A new RTU cabinet and panel will be replaced with a Control Wave unit. The telemetry and electrical systems will be brought up to current standards and will include methane and CO sensors and monitoring, station wiring upgrades, electrical service upgrades, station grounding, telemetry tower upgrades, UPS installation, generator installation, modem and firewall upgrades, station lighting upgrades, and weather station installation/replacement.
Measurement: A new mass flow meter will be installed and connected to the SCADA system so that the Gas Control group can monitor station flows, pressures, and temperatures.
Compliance and Others: New land will have to be acquired to allow for the station relocation and there are currently two sites that are favoured. Either of these options will require significant civil work to ensure a suitable grade on which the station will sit and allow for adequate run off capabilities. The new station will require additional high-pressure pipe to be installed to connect appropriately to the existing network. The location will determine the length of pipe needed to be installed.
$1.2 million allotment for Land acquisition.

Solution Impact: Relocating the station location will mitigate safety risks to employees, contractors, and the general public.

Resources: Company crews, contractor labour and third-party vendor suppliers

Project Timing and Execution Risk: Planning in Year 1, Execution in Year 2. Execution Risk - Weather impacts, resource availability, procurement issues, etc.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - Distribution Stations - Gate, Feeder & A Stations
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	30 - Richmond Hill
	Asset Program (EGI)	DS - Gate, Feeder & A Stations
	Asset Class (EGI)	Distribution Stations
2. Compliance	Compliance Investment	Yes
	Compliance Justification & Code	Small compound, hazardous area classification issues
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (4,559,188)	0.00	$ 5,051,604	1/1/2018

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 2,947,995	$ 1,920,959	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
8567	**2021**	**5**

Investment Name

STJOHN SIDEROAD FEEDER

Alternative Value - Recommended

Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(4,559)	100%
Total	**(4,559)**	**100%**

Compression Stations

ENBRIDGE **Investment Summary Report**	Investment Code **101995**	Report Start Year **2021**	Number of Years **5**
	Investment Name Dehydration Expansion		

Investment Description

Issue/Concern:
This project is to fulfill EGI's obligation to meet Quality of Gas (Moisture Content) at Dawn and blending assumption of storage supplies and upstream pipeline supplies (Vector/Great Lakes). The Dawn Hub operational blends multiple sources of supply on a daily basis and is required to meet Gas Quality set out in C1 Tariff and Interconnect Agreements. The Dawn sendout moisture content is dependent on the daily supply balance (Upstream i.e Vector/Great Lakes), Storage (Dehydrated Supply/Dehy By-pass), and the moisture content of those respective supplies. EGI is responsible for blending all supplies and ensuring that gas supply leaving Dawn is within the Gas Quality Specification of 4 lbs H20/MMscf, as natural gas in combination with liquid water can form methane hydrate. The methane hydrates formed by cooling may plug the valves, the fittings or even pipelines.
Reference: Quality of Gas at Dawn (C1 Tariff and Interconnect Agreements)

Justification:
1. Operational Reliability:
EGI obligation to meet Quality of Gas (Moisture Content) at Dawn and blending assumption of storage supplies and upstream pipeline supplies. Storage design assumes a coincident transmission design in which upstream pipeline supplies are arriving at Dawn to balance the Dawn sendout.

2. Financial:
- EGI faces financial consequences if market supply needs to be replaced in a limited market or in the event of potential revenue loss and damage claims from customers.
- EGI is required to maintain its obligation of 4 lbs H20/MMscf under C1 Tariff and Interconnect Agreements.
- EGI must maintain firm service to all distribution customers, S&T and third party storage providers.

3. Inability to Meet System Growth beyond 2022-23

Assets: New

Related Programs: N/A

Recommended Alternative Description

Scope of Work: Expansion of dehydration facilities by 1 BCF at the Corunna Compressor Station.

Work includes full project gating cycle due to scale and complexity including: stakeholder consultations, planning, detailed design, permit applications, environmental assessment, procurement, retaining a construction contractor, isolations erect buildings if required, prefabrication, hydrotesting, install new piping and auxiliary systems, NDE as required, coating, inspection, train staff, energize system, programming and records updates.

Resources:
Consultant resources for design
Contractor resources for construction and commissioning

Solution Impact: Blending of gas is not required to produce pipeline quality gas leaving Dawn.

Project Timing and Execution Risk:
Year 1: Pre-FEED and FEED study
Year 2: Regulatory, detailed Engineering work , Procurement activities
Year 3: Pre-Fabrication, Civil work
Year 4: Construction, Programming

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - Compression Stations - Improvements
Investment Stage	Short Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	70 - Storage
	Asset Program (EGI)	CS - Improvements
	Asset Class (EGI)	Compression Stations
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (34,457,904)	0.00	$ 41,000,000	1/1/2021

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 4,100,000	$ 22,777,486	$ 12,807,569	$ 1,314,945	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
101995	**2021**	**5**

Investment Name

Dehydration Expansion

Alternative Value - Recommended

Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(34,458)	100%
Total	**(34,458)**	**100%**

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
100901	2021	5

Investment Name

SCOR: K701/2/3 Reliability - Replacement

Investment Description

Issue/Concern:
The operating reliability of K701/2/3 compressor units is poor. These three compressor units account for 20% of available compressor power and their failure frequency is five times greater than comparable - newer - units. Much of the reliability challenge stems from lean burn conversions. During the mid 1990s, EGI embarked on an emissions abatement program, which would see all units retrofitted with low NOx combustion systems. Lean burn (low emissions) systems were readily available for units K704 thru K710 (model KVR). The globally installed base for the KVR compressor model is large. K701 thru K703 are an earlier compressor model (KVT) with a much smaller number of units in the world. Indications from SMAs suggest that there are only four lean burned KVT units in the world, and EGI owns three of them. The KVT lean burn conversion kits have never been designed for mass production and have been plagued with problems. Reliability concerns related to K701/2/3 translate directly into peak day deliverability risk, because all three units are needed to achieve peak day flow rates.

Asset: Compressors K701, K702 and K703.

Related Program: N/A

Recommended Alternative Description

Scope of Work:
-Removal and abandonment of the three plants at the Corunna Compressor Station, associated piping and electrical and remediation of land back to level grade.
-Installation of 20 kilometres of NPS 36 Pipeline between Dawn and Corunna Compressor Station.

Work includes full project gating cycle due to scale and complexity including: stakeholder consultations, planning, detailed design, permit applications, environmental assessment. procurement, retaining a construction contractor, isolate system, demolition of structures/equipment to be replaced, erect buildings if required, prefabricating piping, hydrotesting, install new piping and auxiliary systems, NDE as required, coating, inspection, train staff, energize system, remediating site and records updates.

Solution Impact:
Alternative to provide 118 TJ/d of withdrawal capacity from K701, K702 and K703. Compression retirement identified in previous Asset Management Plan.

Resources:
Consultant resources for design
Contractor resources for abandonment, construction and commissioning

Project Timing and Execution Risks:
This project will need two years of design procurement and construction and requires environmental assessment and regulatory approval. In-service date slated for 2024.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - Compression Stations - Replacements
Investment Stage	Long Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	70 - Storage
	Asset Program (EGI)	CS - Replacements
	Asset Class (EGI)	Compression Stations
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

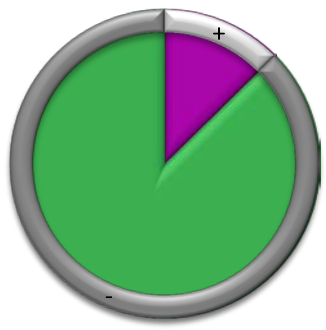
Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
NPS 36 Pipeline	Recommended	$ (136,603,453)	0.00	$ 185,200,000	1/1/2022

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ -	$ 800,000	$ 9,300,000	$ 172,000,000	$ 3,100,000
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Investment Summary Report	Investment Code	Report Start Year	Number of Years
	100901	2021	5
	Investment Name		
	SCOR: K701/2/3 Reliability - Replacement		

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Financial Risk	19,737	13%
Employee And Contractor Safety Risk	0	0%
Environmental Risk And Remediation	0	0%
Public Safety Risk	0	0%
Reputational Risk	0	0%
Total Investment Cost (CA)	(136,603)	87%
Total	**(116,866)**	**100%**

ENBRIDGE Investment Summary Report	Investment Code: 12957	Report Start Year: 2021	Number of Years: 5
	Investment Name: SCOR:100MOD Hdr Valves-Replace		

Investment Description

Issue/Concern:
Operations has identified compressor station yard isolation valves that do not provide sufficient seal quality to provide isolation during normal maintenance activities or emergency situations. Valve condition is under investigation in the Asset Health Review. Condition assessment results are rudimentary. Leaking valve seals are not necessarily valves that leak to atmosphere or pose a loss of containment threat. The valves referenced in this investment are those that allow gas to flow, when in the closed position. These leaking valves pose:
(i) a process safety threat
(ii) a loss of system performance by creating recycle loops
(iii) decreased ability to provide a safe work environment for maintenance activities that require double lock and bleed.
If valve condition is not maintained at a reasonable level, the ability to isolate assets during an emergency will be compromised. Valves in question are sometimes used to separate piping with different MOPs. If these valves are allowed to leak, there is an increased threat of overpressuring lower MOP pipe as gas bleeds through the valve from higher MOP pipe.

Asset: K707 and 704 MOD header valves

Related Programs: N/A

Recommended Alternative Description

Scope of Work:
Solution/Cost Basis: Cost assumes that all MOD valves on the Transmission Header will be replaced. There are a total of 23 valves - all valves are PN100 pressure classification. It is assumed that valves sizes match the size of the Transmission Header (NPS24). Valves include: Project targets all MOD valves associated with K704 & K707.
Work includes design, stakeholder consultations, retaining a construction contractor, prefabricating piping, hydrotesting at shop, laying plates, isolate system likely with a full station outage, cut out existing valves, installing supports as required, install new piping coating as required, NDE, energize system and remediating site.

Resources:
Internal Resources: Engineering, Document Control, Lands Coordinator, Reservoir Group, Instrument and Electrical, Operations, Execution, Finance, Contracts, Warehouse, Safety
External Resources: Engineering Firm, Site Inspector, Construction Contractor & Sub Contractors, Non-Destructive Testing Contractor, Survey Contractor, Concrete Testing/Ground Testing Contractor, Community Engagement, Environmental

Solution Impact: Replacing the valves with new valves will stop the leakage issues. This ensures the MOD valves are capable of preventing mixing of gases at different pressures, directing gas as required and isolation can be obtained when required.
Risks Reduced:
(1) Safety - leaking valves can result in safety risks for all staff and contractors. In addition, leakage can result in damage to infrastructure in the event of ignition.
(2) Infrastructure reliability - Leakage or can interfere with the operation of the facility if valves are required for purposes such as over pressure protection. In the event that separate MOPS can not be kept isolated, derating of systems may be required having significant impacts pending the point in the injection/withdrawal cycle.
(3) Performance degradation. Leaking valves create re-cycle loops that reduce the effectiveness of compression.

Project Timing and Execution Risks:
Planning Year 1.
Execution in Year 2.
Execution Risk such as unavailability of the yard, weather, and injection/withdrawal schedule. Project impacts a crucial area of plant which can affect or be affected by numerous systems.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - Compression Stations - Replacements
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	70 - Storage
	Asset Program (EGI)	CS - Replacements
	Asset Class (EGI)	Compression Stations
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

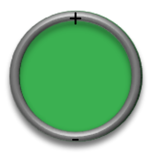
Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (4,839,102)	0.00	$ 5,218,230	1/1/2020

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 5,118,230	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

ENBRIDGE Investment Summary Report	Investment Code **12957**	Report Start Year **2021**	Number of Years **5**
	Investment Name SCOR:100MOD Hdr Valves-Replace		

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(4,839)	100%
Total	**(4,839)**	**100%**

Investment Summary Report	Investment Code	Report Start Year	Number of Years
	3460	2021	5
	Investment Name: SCOR:60007-Fdn Blk-Replace		

Investment Description

Issue/Concern: Due to the age of the compressor infrastructure, operating hours and oil contamination, engine block foundations are deteriorating. Industry benchmarks suggest that reciprocating engine block foundations degrade in 25 years or less for engines that run 24/7. Excessive bearing deflections place cyclic stresses on the crankshaft of the unit leading to increased frequency of bearing failure and increased potential for a crankshaft fatigue failure. Unit reliability will diminish dramatically if repairs are not performed. The worst case consequence is unit unavailability during a design day. Compressor foundations have been considered in the Asset Health Review. Condition assessment is largely visual. A telltale sign of poor foundation condition is the existence of cracks on the surface of the foundation, with oil seeping out of the crack. Cracks typically extend to a depth that is consistent with the bottom of the unit's anchor bolts. Without remediation, failing foundations will allow unit settlement, creating a misalignment of bearings. Frequency of bearing failures increases - reducing operation reliability. Collateral damage to the crankshaft is also common.

Asset: K707 Compressor foundation.

Related Programs: Not Applicable.

Recommended Alternative Description

Scope of Work: Solution/Cost Basis: Cost estimate is based on historical costs for similar projects and SMA review. The project will take approximately 90 days (two 10-hour shifts) to complete with EGI mechanics providing facilitation support to the manufacturer representative who will be contracted as the third party providing labour and execute the work.
Assumptions include:
1) Volumes of concrete removed and re-installed do not vary from previous foundations replaced.
2) No new additional work to support and secure the compressor unit is required.
3) Foundation blocks were installed at different times and are part of different vintages. It is assumed the vintage worked on is not more difficult to remove than foundations used for basis of the estimate. Scope: Remove and replace the foundation that is failing on K707. The manufacturers expected life span is approximately 25 years The foundation of this machine is not 40+ yrs old and is beginning to crack due to fatigue failure.
Task Breakdown:
1) Set the up the work area. Contractors are to remove the piping and cables that will interfere with the work area.
2) Remove the compressor cylinders and distance pieces.
3) Build the dust containment shelter around the machine and install the air filtration units.
4) Remove the foundation (cement and rebar block, "10'w x 8'h x 30'l).
5) Prepare the existing cement matt for the new foundation.
6) Install the new rebar and inspect.
7) Build the cement forms and reinforce. Pour the cement in one continuous pour. Remove the cement form and remove any high points.
8) Install compressor distance pieces and cylinders. Install piping and cables.
9) Complete PSSR with Operations.
10) Perform run tests and then return to Operations.

Resources:
One project lead for the duration of the project, one mechanic (days), one mechanic (nights), one Dresser Rand project manager, one Dresser Rand Field service representative, approximately four to eight contract MWs for the duration of the work, approximately six Dresser Rand mechanics for the duration of the work, a mechanical contractor team of four (two weeks for removal, three weeks for reinstallation), one electric contractor team of three (one week for removal, two weeks for reinstallation), four mechanics during final assembly for two weeks, crane company for heavy lifts (approximately five days)

Solution Impact:
This project replaces the entire foundation of the machine. Failure of a foundation can result in a crank failure that could take the machine out of service for more than a year and be as much as $10 million to complete the crankshaft replacement. The new foundation will provided an additional 25 years of life to the component of the machine. Risks Reduced: Increased reliability of the equipment reduces customer satisfaction risk. Another risk reduced is a long-term outage due bearing failures and possible (ensuing) crankshaft failure.

Project Timing and Execution Risks:
Installation Year 1:The scope will take ~90 days (two 10-hour shifts) to complete the work with EGI mechanics providing facilitation support. To complete the project, the contract will need to be awarded within the first two months of the year to ensure the required technical support, engineering, materials and labour can be secured for the project.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - Compression Stations - Replacements
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	70 - Storage
	Asset Program (EGI)	CS - Replacements
	Asset Class (EGI)	Compression Stations
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Investment Summary Report

Investment Code	Report Start Year	Number of Years
3460	2021	5

Investment Name

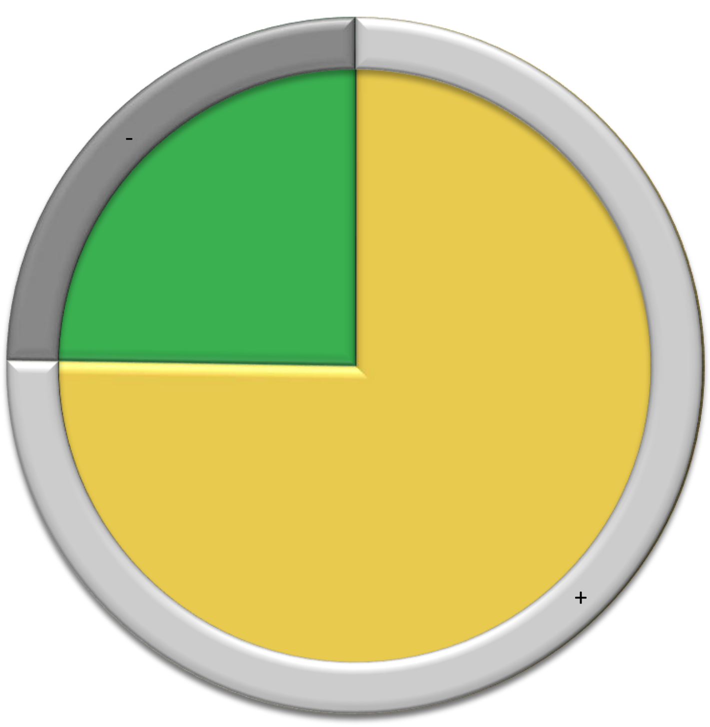
SCOR:60007-Fdn Blk-Replace

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (1,898,148)	0.00	$ 2,050,000	1/1/2020

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 2,050,000	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Gas Storage Reliability (CA)	5,778	75%
Avoided GHG Emissions (CA)	0	0%
Budget Savings CAPEX (CA)	0	0%
Budget Savings OPEX (CA)	0	0%
Cost Avoidance CAPEX (CA)	0	0%
Cost Avoidance OPEX (CA)	0	0%
Employee And Contractor Safety Risk	0	0%
Energy Efficiency (CA)	0	0%
Environmental Risk And Remediation	0	0%
Financial Risk	0	0%
Operational Risk	0	0%
Public Safety Risk	0	0%
Reputational Risk	0	0%
Revenue Impact (CA)	0	0%
Operational Disruption Risk (Gas) (CA)	0	0%
Operational Disruption Risk (Liquids) (CA)	0	0%
Total Investment Cost (CA)	(1,898)	25%
Total	**3,880**	**100%**

Investment Code	Report Start Year	Number of Years
1811	2021	5

ENBRIDGE

Investment Summary Report

Investment Name

SCOR:Meter Area-Upgrade (Phase 1)

Investment Description

Issue/Concern: There are two drivers for replacement of the existing meter area:
- The existing cross flow header can be subjected to very high pipe velocities creating flow induced vibration.
- The meter area is no longer used to meter pool inventory and can be made safer by replacing with modern buried pipe designs.

The existing cross flow header allows interconnection of the DOW header (Maximum Operating Pressure (MOP) of 1550 psig) with all remaining headers (MOPs of 1200 psig and 900 psig). This interconnection is necessary during low-end withdrawal from DOW. Low-end withdrawal from DOW requires that the DOW header be allowed to flow into SCOR on first stage compression (MOP of 1200 psig). Due to the MOP differences between DOW and the remaining headers, the DOW header is unable to connect directly to lower pressure compressors on the suction side.

The cross flow header was added when the DOW reservoir was developed. The existing cross flow header interconnects DOW to the lower pressure headers by way of manual ball valves. The DOW pool pipeline and headers system is sized at NPS 24. Sizing of the cross flow header is such that DOW flows into 1200 psig headers through valves as small as NPS 12. This discrepancy creates a pinch point with excessively high velocities (>200 ft/s), causing flow-induced vibration. In addition to the sizing issue, CSA Z662 code requires that automatic over-pressure protection (OPP) be provided whenever pipe of dissimilar MOPs are connected. Suitable OPP does not exist on the current cross flow header.

Risk can be dramatically reduced by replacing the existing cross flow header with one that is appropriately sized and with over-pressure protection. The existing meter area is no longer used for inventory management - it is simply the flow path used to convey gas back and forth from reservoirs. Limited cross-flow functionality is provided in the current meter area piping. The pipe is of unknown material composition, with unknown strength characteristics, and is comprised of many flange connections in an area frequently accessed by personnel. Piping is also above-grade. Tolerance of damage risks related to above-grade piping is no longer warranted, and can be reduced by replacing with buried pipe.

Asset: SCOR header system and Meter Area

Related Programs: 500440; Resolution of this concern stands alone, but SCOR compressor replacement (replacement of K701/2/3; Inv# 100901) relies on resolution of this concern.

Recommended Alternative Description

Scope of Work: Install Electrical Control building, replace meter run piping and install new header cross-over and isolation valves for Ladysmith and Dow-Moore pool lines, install west section of new NPS 30 A, B, C headers.
New piping will be designed with pressure control and protection provisions needed to safely manage multiple pipeline and header MOPs ranging from 900 psig to 1550 psig. Work includes full gating cycle due to scale and complexity including: stakeholder consultations, planning, detailed design, permit applications, procurement, retaining a construction contractor, isolating the system, installing a temporary drainage system, demolition of structures/equipment to be replaced, erecting buildings if required, installing air system modifications if required, prefab piping, hydrotesting, demolishing meter runs, installing new piping and auxiliary systems, NDE as required, coating, inspection, training staff, energizing the system, remediating the site, and performing records updates.

Resources: Internal: Engineering, Doc Control, Lands, Reservoir Group, Instar and Elect, Operations, Execution, Finance, Contracts, Warehouse, Safety, EHS, Procurement
External: Engineering Firm, Site Inspector, Construction Contractor & Sub Contractors, Non-Destructive Testing Contractor, Survey Contractor, Concrete Testing/Ground Testing Contractor, Community Engagement, Environmental

Solution Impact:
(1) Replacement pipe will be welded in place. Replacement pipe will be a single run per header as compared to the current multiple runs. Fittings such as flanges, bolt in meters and bolt on valves will be eliminated. All these factors work to reduce the number of potential leak paths.
(2) Piping would be buried reducing risk of vehicle impact.
(3) Many valves in the existing meter run area are original installations and reaching the end of their life cycle with increased risk of internal bypass. Replacements will be able to fully seal.
(4) Diameter change at existing cross-flow header will be eliminated. This prevents piping from exceeding unsafe gas velocity.
(5) All new equipment would be purchased and installed to modern specifications designed specifically toward the high pressures the facility can experience. Replacement pipe will be designed to modern standards (CE, CVN testing, DWTT etc.).
(6) Replacement includes Pressure Control (PC) and OPP designed to address range of MOPs in EGI systems. Modifications that result in operational bottle necks installed over the history of EGI will be incorporated into a permanent, functional installation.

Project Timing and Execution Risks:
Year 1-Design work, permits, Approvals
Year 2-Procure, permits
Year 3-Construction
Challenges:
- The project is occurring in an area where modifications have been made for more than 50 years. Record keeping has gone through varying levels of detail during this time. Transfer between record systems creates a risk of unidentified pipe being discovered during execution. Should this occur during execution, short delays may be experienced.
- The work area has a significant amount of sand backfill. Combined with the water table, excavation will require shoring and drainage systems.
- This project replaces a vital section of plant piping execution delays will impact injection/withdrawal schedules.
- Material delays will impact execution of the project. Long lead items should be ordered in advance.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - Compression Stations - Improvements
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	70 - Storage
	Asset Program (EGI)	CS - Improvements
	Asset Class (EGI)	Compression Stations
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Investment Code	Report Start Year	Number of Years
1811	2021	5

ENBRIDGE

Investment Summary Report

Investment Name

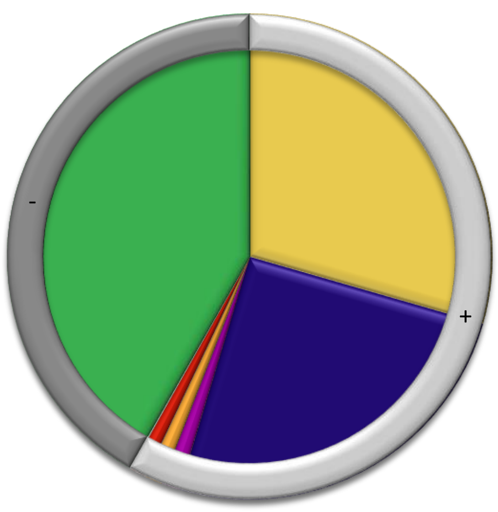
SCOR:Meter Area-Upgrade (Phase 1)

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (4,879,734)	0.60	$ 19,398,316	1/1/2018

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 12,898,501	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Gas Storage Reliability (CA)	8,708	29%
Cost Avoidance CAPEX (CA)	7,450	25%
Financial Risk	364	1%
Environmental Risk And Remediation	339	1%
Public Safety Risk	317	1%
Avoided GHG Emissions (CA)	22	0%
Budget Savings OPEX (CA)	12	0%
Cost Avoidance OPEX (CA)	0	0%
Budget Savings CAPEX (CA)	0	0%
Revenue Impact (CA)	0	0%
Total Investment Cost (CA)	(12,342)	42%
Total	**4,870**	**100%**

Investment Summary Report	Investment Code	Report Start Year	Number of Years
ENBRIDGE	**500440**	**2021**	**5**
	Investment Name: SCOR:Meter Area-Upgrade (Phase 2)		

Investment Description

Issue/Concern:
There are two drivers for replacement of the existing meter area:
- The existing cross flow header can be subjected to very high pipe velocities, creating flow induced vibration.
- The meter area is no longer used to meter pool inventory and can be made safer by replacing with modern buried pipe designs.

The existing cross flow header allows interconnection of the DOW header (Maximum Operating Pressure (MOP) of 1550 psig) with all remaining headers (MOPs of 1200 psig and 900 psig). This interconnection is necessary during low-end withdrawal from DOW. Low-end withdrawal from DOW requires that the DOW header be allowed to flow into SCOR on first stage compression (MOP of 1200 psig). Due to the MOP differences between DOW and the remaining headers, the DOW header is unable to connect directly to lower pressure compressors on the suction side. The cross-flow header was added when the DOW reservoir was developed. The existing cross flow header interconnects DOW to the lower pressure headers by way of manual ball valves. The DOW pool pipeline and headers system is sized at NPS 24. Sizing of the cross flow header is such that DOW flows into 1200 psig headers through valves as small as NPS 12. This discrepancy creates a pinch point with excessively high velocities (>200 ft/s), causing flow-induced vibration.

In addition to the sizing issue, CSA Z662 code requires that automatic over-pressure protection (OPP) be provided whenever pipe of dissimilar MOPs are connected. Suitable OPP does not exist on the current cross-flow header. Risk can be dramatically reduced by replacing the existing cross-flow header with one that is appropriately sized and with over-pressure protection.

The existing meter area is no longer used for inventory management - it is simply the flow path used to convey gas back and forth from reservoirs. Limited cross flow functionality is provided in the current meter area piping. The pipe is of unknown material composition, with unknown strength characteristics, and is comprised of many flange connections in an area frequently accessed by personnel. Piping is also above-grade. Tolerance of damage risks related to above-grade piping is no longer warranted, and can be reduced by replacing with buried pipe.

Asset: SCOR Header system and Meter Area

Related Programs: 1811 (Phase 1); Resolution of this concern stands alone, but SCOR compressor replacement (Replacement of K701/2/3; Inv # 100901) relies on resolution of this concern.

Recommended Alternative Description

Scope of Work: Replace meter run piping and install new header cross-over and isolation valves for the Wilkesport, South Kimball, Seckerton, Corunna and Mid Kimball pool lines. Install east section of new NPS 30 A, B, C headers and tie in east and west header sections. New piping will be designed with pressure control and protection provisions needed to safely manage multiple pipeline and header MOPs ranging from 900 psig to 1550 psig. Work includes full gating cycle due to scale and complexity including: stakeholder consultations, planning, detailed design, permit applications, procurement, retaining a construction contractor, isolating the system, installing a temporary drainage system, demolition of structures/equipment to be replaced, erecting buildings if required, installing air system modifications if required, prefab piping, hydrotesting, demolishing meter runs, installing new piping and auxiliary systems, NDE as required, coating, inspection, training staff, energizing the system, remediating the site, and performing records updates.

Resources:
Internal: Engineering, Doc Control, Lands, Reservoir Group, Instar and Elect, Operations, Execution, Finance, Contracts, Warehouse, Safety. EHS, Procurement
External: Eng. Firm, Site Inspector, Construction Contractor & Sub Contractors, Non-Destructive Testing Contractor, Survey Contractor, Concrete Testing/Ground Testing Contractor, Community Engagement, Environmental

Solution Impact:
(1) Replacement pipe will be welded in place. Replacement pipe will be a single run per header as compared to the current multiple runs. Fittings such as flanges, bolt in meters and bolt on valves will be eliminated. All these factors work to reduce the number of potential leak paths.
(2) Piping would be buried, reducing risk of vehicle impact.
(3) Many valves in the existing meter run area are original installations and reaching the end of their life cycle with increased risk of internal bypass. Replacements will be able to fully seal.
(4) Diameter change at existing cross-flow header will be eliminated. This prevents piping from exceeding unsafe gas velocity.
(5) All new equipment would be purchased and installed to modern specifications designed specifically toward the high pressures the facility can experience. Replacement pipe will be designed to modern standards (CE, CVN testing, DWTT etc.).
(6) Replacement includes Pressure Control (PC) and OPP designed to address a range of MOPs in EGI systems. Modifications that result in operational bottle necks installed over the history of EGI will be incorporated into a permanent, functional installation.

Project Timing and Execution Risks:
Year 1-Design work, permits, Approvals
Year 2-Procure, permits
Year 3-Construction

Challenges:
- The project is occurring in an area where modifications have been made for more than 50 years. Record keeping has gone through varying levels of detail during this time. Transfer between record systems creates a risk of unidentified pipe being discovered during execution. Should this occur during execution, short delays may be experienced.
- The work area has a significant amount of sand backfill. Combined with the water table, excavation will require shoring and drainage systems.
- This project replaces a vital section of plant piping execution delays will impact injection/withdrawal schedules.
- Material delays will impact execution of the project. Long lead items should be ordered in advance.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - Compression Stations - Improvements
Investment Stage	Executing		

Investment Summary Report

Investment Code	Report Start Year	Number of Years
500440	2021	5

Investment Name

SCOR:Meter Area-Upgrade (Phase 2)

Investment Overview

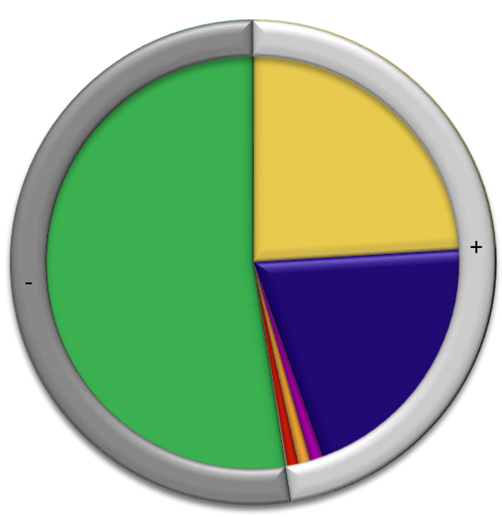
1. Project Information	State/Province	Ontario
	Operating Area (EGI)	70 - Storage
	Asset Program (EGI)	CS - Improvements
	Asset Class (EGI)	Compression Stations
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (11,568,698)	0.39	$ 25,122,575	1/1/2018

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 2,434,760	$ 18,884,388	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Gas Storage Reliability (CA)	8,708	24%
Cost Avoidance CAPEX (CA)	7,450	21%
Financial Risk	364	1%
Environmental Risk And Remediation	339	1%
Public Safety Risk	317	1%
Avoided GHG Emissions (CA)	22	0%
Budget Savings OPEX (CA)	12	0%
Cost Avoidance OPEX (CA)	0	0%
Budget Savings CAPEX (CA)	0	0%
Revenue Impact (CA)	0	0%
Total Investment Cost (CA)	(19,031)	53%
Total	**(1,819)**	**100%**

ENBRIDGE **Investment Summary Report**	Investment Code **13034**	Report Start Year **2021**	Number of Years **5**
	Investment Name SCRW:Station-Renewal In-Place		

Investment Description

Issue/Concern: Due to the age of the facility, the compressor station experiences process safety concerns (lack of automation; unit valves, electrostatic discharge (ESD), dehydration and incinerator systems), obsolescence issues (compressor, building, electrical), code concerns (location of recycle valve/line), lack of auxiliary power, inability to support site security devices such as cameras, and setback concerns related to neighbouring occupied buildings and the nearby rail line.

Justification: Modernize the facility to comply with current code and design standards.

Asset: Crowland Compressor Station

Related Program: This project is under consideration in conjunction with an overall Crowland upgrade. Issues related to the wells and gathering system should be considered together with the compressor station's issues/concerns.

Recommended Alternative Description

Scope of Work: The compressor station will be rebuilt in place including:
- Installation of a new administration building, auxiliary building, compressor building, utilities, site safety and security system.
- Decommissioning of the compressor system
- Dehydration system instrumentation and controls upgrade

Work includes full project gating cycle due to scale and complexity including stakeholder consultations, planning, detailed design, community consultations, permit applications, environmental assessments, procurement, retaining a construction contractor, isolating the system, demolition of structures/equipment to be replaced, erecting buildings, prefabricating piping, hydrotesting at shop, installing new piping and equipment, NDE as required, coating as required, inspection, training staff, energizing the system, remediating the site, and performing records updates.

Resources:
Internal Resources: Engineering, Document Control, Lands Coordinator, Reservoir Group, Instrument and Electrical, Operations, Execution, Finance, Contracts, Warehouse, Safety, EHS, Procurement
External Resources: Engineering Firm, Site Inspector, Construction Contractor and Sub-Contractors, Non-Destructive Testing Contractor, Survey Contractor, Concrete Testing/Ground Testing Contractor, Community Engagement, Environmental

Solution Impact:
The new facility will be designed to current code requirements with remote operation capabilities.

Project Timing and Execution Risks: Project timing may be revised during the Front End Engineering Design (FEED) and detailed design phases. Current approach is to minimize potential station downtime.
Year 1 - FEED, Detailed Design, Permitting, Approvals, Permitting, Procurement, Construction Ramp up
Year 2 - Procurement, Prefabrication, Demolition and Construction
Year 3 - Restoration and Construction, Commissioning

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - Compression Stations - Improvements
Investment Stage	Long Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	70 - Storage
	Asset Program (EGI)	CS - Improvements
	Asset Class (EGI)	Compression Stations
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Operate Crowland without Compression	Recommended	$ (21,663,007)	0.00	$ 27,903,084	1/1/2022

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ -	$ 5,629,668	$ 12,171,192	$ 5,495,028	$ 4,607,196
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ 1,765,906	$ -	$ -

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
13034	2021	5

Investment Name

SCRW:Station-Renewal In-Place

Alternative Value - Recommended

	Value Function Measure	Value	Value in Percentage
	Financial Risk	648	3%
	Total Investment Cost (CA)	(21,663)	97%
	Total	**(21,015)**	**100%**

Transmission Pipe and Underground Storage

Investment Summary Report	Investment Code	Report Start Year	Number of Years
	6377	**2021**	**5**
	Investment Name: PCRW:Wells-Upgrade		

Investment Description

Issue/Concern: Wells at Crowland are much older than other wells in EGI. Due to age, the wells were constructed to a production standard which would normally be retired after 10 years. Instead, the wells were converted to Storage service in the early 1970's and continue to operate ever since. Many wells have been relined, increasing the risk of leaks. Most wells possess only two casings - the current standard requires a minimum of three casings. The two-casing design at Crowland is comprised of an inner casing that runs from the surface to the reservoir (about 225m) plus a surface casing that runs from the surface to a depth of about 20 metres. Most wells do not have an intermediate casing with cement between the inner and intermediate casings, however, there is cement between the inner casing and the surrounding rock. This provides a poor barrier to gas flow should the inner casing fail. In addition, none of the wells at Crowland employ wellheads and master valves. Instead, the inner casing is simply connected to a flanged 1/4 turn valve without wing valves or wellhead vents. The surface casing is separated from the surface using cement. There are no casing vents and part of the inner casing (typically a length of 2 to 16 inches) is exposed at the surface. The lack of casing vents eliminates normal approaches to controlling a failed well. Vertilogs have been performed in the last 5 years, and indicated that the inner casing integrity is adequate, although two of 26 wells needed to be abandoned. Currently, there are 24 wells remaining. Bond logs have not been performed yet to determine the condition of cement at sulphur layers. Primary concerns are:
(1) Code compliance of the wells and wellheads. Technically, these wells were constructed before CSA Z341 came into force, and are grandfathered. However, a well failure would likely be viewed negatively by technical regulators.
(2) Risk to employees and the public - in the event of a loss of containment, there are insufficient barriers to gas flow. Public risk also extends to possible sulphur contamination of well water at surface levels. In addition to the wells, much of the gathering system is as old as the wells. The gathering system is operating at <30% SMYS, which means that they have not be considered for integrity inspections until recently and that the gathering system pipe condition is unknown after 50 to 100 years of operation.

Asset: Crowland wells and gathering system.

Related Programs: This investment is under consideration in conjunction with other Crowland investments in the Distribution Station asset class and Compressor Station asset class - Issues related to the wells and gathering system should be considered together with the additional distribution station and compressor station issues/concerns

Recommended Alternative Description

Scope of Work:
Solution/Cost Basis: Cost estimate allows for: drilling applications and well locations studies, design, materials, core sampling, drilling two new vertical wells (Vwells) and well heads/master valves to 12 existing Vwells, stimulate new wells and 12 existing wells, and upgrade wellheads for 12 existing wells. The majority of design and installation work will be performed by third parties.
Assumptions:
1) The project schedule is influenced by reservoir pressures, regulatory approvals and environmental factors.
2) Environmental findings may impact execution costs.
3) Crowland is located in a marshy area which may impact execution and costs.
Work sequence is as follows:
1) Drill a vertical well to core through the confining geological formations and the storage zone. The core will be tested and an integrity study will be completed to determine if stimulation operations can be performed in the sandstone storage zone. If the integrity tests are positive, they will be used as the basis for drilling permit applications for two Vwells.
2) Obtain permits to drill two new Vwells.
3) Obtain approval from MNRF to remediate remaining wells.
4) Install well pads.
5) Mobilize drilling equipment.
6) Drill new Vwells.
7) Stimulate Vwells
8) Replace Vwell wellheads.
9) Demobilize.
10) Remediate/restore.

Resources:
1) Gas Storage Reservoir Department - Project management, obtain MNRF and OEB permits, project execution
2) EGI Regulatory - Obtain permits
3) EGI EHS Department - Environmental assessment, species at risk and archeological study; final environmental reports
4) EGI Procurement Group - Contracts and purchasing for casing, wellheads and valves.
5) EGI - Aboriginal Affairs - Consultation
6) Third-party contractors - Wellsite supervision, drilling contractor, directional drilling contractor, core testing laboratories, well stimulation company, civil contractor (build pad and cleanup), mechanical contractor, logging contractors

Solution Impact: Results of the core integrity testing will verify that the confining geological formations are suitable for storage and provide inputs needed to simulate the Hwells. Up to eight existing Vwells will be abandoned, reducing risk.

Risks Reduced:
1) Loss of containment from exposed inner casing above the surface level of the well.
2) Effects of well casing corrosion, where exposed to corrosive sulphur, can be mitigated more readily with modern well heads and master valves. Limits pressurized gas, leaking through the well casing, and contaminating well water at surface with sulphur.
3) Effects of deteriorated cement, between the casing and rock, can be mitigated more readily with modern well heads and master valves. Existing cement is not resistant to the effects of sulphur and has reduced life expectancy. Compromised cement may allow well casing leaks to migrate to surface.

Project Timing and Execution Risks:
Year 1: Prep for Vwell permits - ER, SAR, Archeay, apply to MNRF/OEB, order long lead items - wellheads, master valves, casing, drill and core well, test core and report, plan well stimulations, apply to MNRF/OEB, order long lead items (wellheads, master valves, ESVs, casing) and drilling contracts.
Year 2: Drill wells, install pipelines, test wells and put wells in service.
Year 3: Abandon existing Vwells.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - Transmission Pipe & Underground Storage - Replacements
Investment Stage	Long Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	70 - Storage
	Asset Program (EGI)	TPS - Replacements
	Asset Class (EGI)	Transmission Pipe & Underground Storage
2. Compliance	Compliance Investment	Yes
	Compliance Justification & Code	Wellhead requiring upgrade to be in compliance with Section 6.3.1 of CSA Z341-18.

ENBRIDGE Investment Summary Report	Investment Code	Report Start Year	Number of Years
	6377	2021	5
	Investment Name: PCRW:Wells-Upgrade		

3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Investment Summary Report

Investment Code	Report Start Year	Number of Years
6377	2021	5

Investment Name

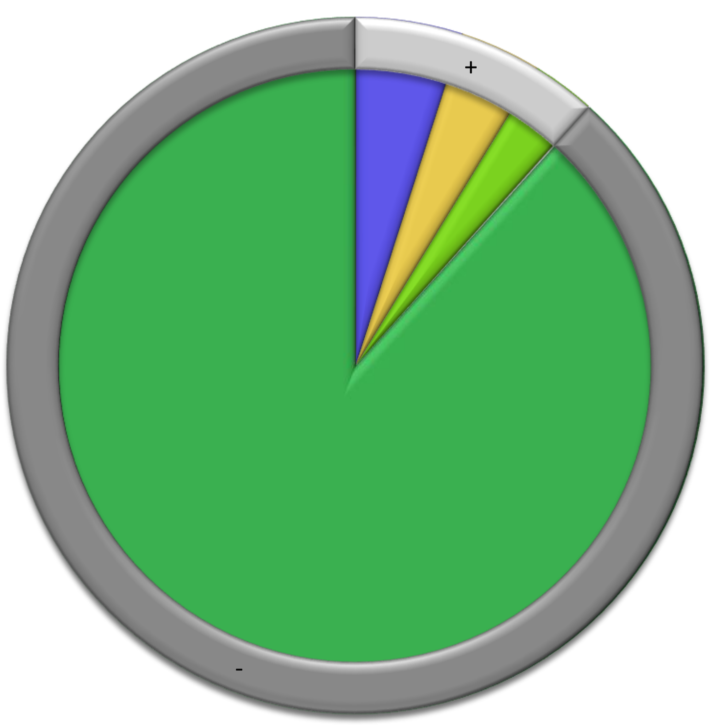
PCRW:Wells-Upgrade

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (7,207,017)	0.03	$ 11,648,011	1/1/2023

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ -	$ -	$ -	$ 443,352	$ 1,290,371
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ 3,000,000	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Avoided GHG Emissions (CA)	416	5%
Gas Storage Reliability (CA)	321	4%
Budget Savings OPEX (CA)	245	3%
Environmental Risk And Remediation	3	0%
Reputational Risk	3	0%
Employee And Contractor Safety Risk	1	0%
Budget Savings CAPEX (CA)	0	0%
Cost Avoidance CAPEX (CA)	0	0%
Cost Avoidance OPEX (CA)	0	0%
Energy Efficiency (CA)	0	0%
Financial Risk	0	0%
Operational Risk	0	0%
Public Safety Risk	0	0%
Revenue Impact (CA)	0	0%
Operational Disruption Risk (Gas) (CA)	0	0%
Operational Disruption Risk (Liquids) (CA)	0	0%
Total Investment Cost (CA)	(7,452)	88%
Total	**(6,463)**	**100%**

Real Estate and Workplace Services

ENBRIDGE Investment Summary Report	Investment Code	Report Start Year	Number of Years
	8701	**2021**	**5**
	Investment Name: Kelfield Operations Centre		

Investment Description

Issue/Concern: The Kelfield office, owned by EGI, is in poor physical condition and is considered obsolete in its functionality and utilization. It is an old facility with an approximate age of 56 years.

Physical Obsolescence: The acceptable EGI standard for the physical condition is a Facility Condition Index (FCI) of 0 to 5%. The current FCI of the facility based on this study is 10.47%. Therefore, the physical condition of the facility does not meet EGI acceptable standards.

Functional Obsolescence – Building: The acceptable EGI standard for the functional condition is 0. A functional condition between 0 and 49% is considered correctable at the current location. The current facility Adequacy Index (AI) is 71%. Based on the FCI/AI graph, the current recommendation for the existing facility is to increase the site area by purchasing the abutting property, demolish existing building, and re-build the facility on the combined sites to accommodate current EGI standards.

Functional Obsolescence – Site: The site does not meet operational requirements for size and vehicular circulation. The yard has only one point of access. The yard size is smaller than EGI standard yard size requirements. The current yard size is 0.3 acres. EGI standard yard size is 2.5 acres. The existing building requires expansion by approximately 7,200 square feet to meet the need for current staff and EGI functional requirements. Building addition on the property entails further reduction in the yard and parking areas. Both the building and site area are too small to meet current EGI standards. The current building is approximately 7,724 square feet and the ideal building size, based on EGI design standards, is estimated to be 14,924 square feet, with a site area of approximately five acres. There is no opportunity for building expansion at the current location. It is understood that the location of the facility works well for EGI operations.

Asset: 40 Kelfield Street, Etobicoke, ON.

Related Program: N/A

Recommended Alternative Description

Scope of Work:
The assets in scope are located at 40 Kelfield Street, Etobicoke, ON. The nature of work is the development of adjacent property, construction and fit-up of a new building.
Sell the existing property; purchase a property suitable in size to accommodate the required program. Required size of new property is approximately 3.5 acres.

Solution Impact: Purchasing the extra land will ensure adequate yard area for current activities and a new building will correct the identified operational deficiencies, using less energy and emitting less greenhouse gases. Once the new facility is occupied the old facility will be demolished. The service life of the new facility will be 25-40 years.

Timing and Execution Risks:
The Project duration is 36 months as described below:
0 – 3 months: Programming, design development
3 – 6 months: Site acquisition
6 – 12 months: Site plan agreement, permit & tender documents, permit and tender process
12 – 14 months: Contract award and winter contingency as required
14 – 28 months: Construction
28 – 30 months: Fit-up and occupancy
30 – 36 months: Disposition of the old property and remaining site activity

Risks include contractor delays and material delivery delays or defects.

Expenditures :
The total cost for the project is $6.8M net capital which includes a working construction cost contingency of 15%. Construction costs are determined based on historical EGI project costs and land values are determined using marketplace comparisons. The project also leverages national pricing agreements with furniture, walls, and flooring manufacturers. The project costs are based on a Class 5 estimate.

Resources:
Professional resources for design and engineering will be contracted from the marketplace. EGI has historically retained architectural and engineering consulting services for the execution of similar projects.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - Real Estate & Workplace Services - Furniture/Structures & Improvements
Investment Stage	Short Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	10 - Toronto
	Asset Program (EGI)	REWS - Furniture/Structures & Improvements
	Asset Class (EGI)	Real Estate & Workplace Services
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Investment Summary Report

Investment Code	Report Start Year	Number of Years
8701	**2021**	**5**

Investment Name

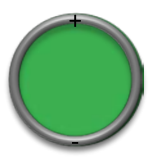
Kelfield Operations Centre

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (9,532,338)	0.00	$ 10,800,000	1/1/2021

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 5,000,000	$ 4,700,000	$ 1,100,000	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ 200,000	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(9,532)	100%
Total	**(9,532)**	**100%**

ENBRIDGE **Investment Summary Report**	Investment Code **3639**	Report Start Year **2021**	Number of Years **5**
	Investment Name Kennedy Road Expansion		

Investment Description

Issue/Concern:
Overall, the existing building at the Kennedy Road facility is too small to meet current EGI standards. The separation of offices and warehouse into two separate buildings is not convenient for staff and causes operational and workplace difficulties and inefficiencies. The configuration of site functions and circulation is inefficient. The yard area is too small to meet current EGI standards. Building expansion on the same property will further reduce the size of the yard area and will cause additional pressure on parking and circulation. Based on the site deficiencies and space limitations, relocation to another property is recommended. This option may no longer be possible so further analysis is required depending on the ability to procure adjacent property or appropriately-sized property nearby. The analysis will look at the possible vertical industrial solution to meet the needs of the business.

Physical Obsolescence: The acceptable EGI standard for the physical condition is a FCI of 0 to 5%. The current FCI of the facility based on this study is 6.51%. Therefore, the physical condition of the facility does not meet EGI acceptable standards.

Functional Obsolescence – Building: The acceptable EGI standard for the functional condition is 0. A functional condition between 0 and 49% is considered correctable at the current location. The current facility AI is 95%. Based on the FCI/AI graph, the current recommendation for the existing facility is to increase the site area by purchasing the adjacent property, demolish existing building, and re-build the facility on the combined sites to accommodate current EGI standards.

Functional Obsolescence – Site: The site does not meet operational requirements for size and vehicular circulation. Access and exit from Kennedy is difficult and poses operational inefficiencies. The yard size is smaller than EGI standard yard size requirements. The current yard size is 1.3 acres. EGI standard yard size is 2.5 acres. The existing building requires expansion by approximately 11,000 square feet to meet the need for current staff and EGI functional requirements. Building additions on the property entail further reduction in the yard and parking areas.

Asset: 3157 Kennedy Road, Scarborough, ON.

Related Program:N/A

Recommended Alternative Description

Scope of Work: Sell the existing property, purchase a property suitable in size to accommodate the required program. Required size of new property is approximately 5 acres.

The project will correct operational and workplace inefficiencies, using less energy and emit less greenhouse gases on the combined site. This strategy will leverage current site improvements and keep land acquisition costs to a minimum by joining the currently vacant neighboring property.

The assets in scope are located at 3157 Kennedy Road, Scarborough, ON. The nature of work includes development of the adjacent property and construction and fit-up of a new building.

Solution Impact: The service life of the new facility will be 25-40 years.

Timing and Execution Risks:
The Project duration is 36 months:
0 – 3 months: Programming, design development
3 – 6 months: Site acquisition
6 – 12 months: Site plan agreement, permit and tender documents, permit and tender process
12 – 14 months: Contract award and winter contingency as required
14 – 28 months: Construction
28 – 30 months: Fit-up and occupancy
30 – 36 months: Disposition of old property

Risks include contractor delays and material delivery delays or defects.

Expenditures:
The total cost for the project is $26.8M net capital which includes a working construction cost contingency of 15%. Construction costs are determined based on historical EGI project costs and estimated land values are based on marketplace comparisons. The project also leverages national pricing agreements with furniture, walls, and flooring manufacturers. The project costs are based on a Class 5 estimate.

Resources:
External professional resources for design and engineering along with a construction company will be contracted for the project. Historically, EGI has retained architectural and engineering consulting services and general construction contractors for the execution of similar projects.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - Real Estate & Workplace Services - Furniture/Structures & Improvements
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	10 - Toronto
	Asset Program (EGI)	REWS - Furniture/Structures & Improvements
	Asset Class (EGI)	Real Estate & Workplace Services
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	2nd floor office space not accessible for occupancy Barrier free accessibility is non-compliant to Ontario Building Code Building has exceeded allowable occupancy Kennedy 45 SF/person VPC average is 145 SF/person
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

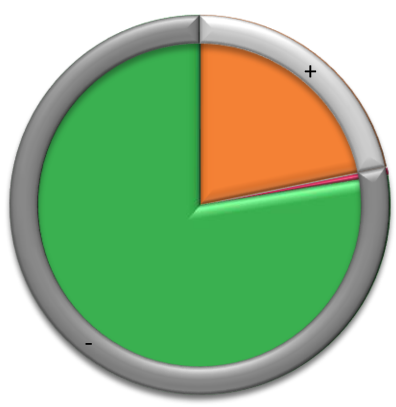
Investment Summary Report	Investment Code	Report Start Year	Number of Years
	3639	2020	5
	Investment Name		
	Kennedy Road Expansion		

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 2	Recommended	$ (17,334,254)	0.28	$ 26,300,000	9/1/2020

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 1,000,000	$ 12,000,000	$ 2,000,000	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ 500,000	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Cost Avoidance OPEX (CA)	6,767	22%
Cost Avoidance CAPEX (CA)	0	0%
Budget Savings CAPEX (CA)	0	0%
Budget Savings OPEX (CA)	0	0%
Revenue Impact (CA)	0	0%
Avoided GHG Emissions (CA)	(30)	0%
Energy Efficiency (CA)	(183)	1%
Total Investment Cost (CA)	(24,102)	78%
Total	**(17,547)**	**100%**

ENBRIDGE Investment Summary Report	Investment Code **6087**	Report Start Year **2021**	Number of Years **5**
	Investment Name MSB Demolition & New Administrative Parking		

Investment Description

Issue/Concern:
The fleet garage (Mechanical Services Building) is located at VPC. Fleet services are now outsourced to third-party providers. As such, a review of remaining industrial activities within the building will be undertaken to determine appropriate facilities for relocation. It is expected when the building is vacant that it will be demolished for administrative parking on site. The capital funds have been re-purposed for the VPC Annex/Metershop Area Renovations project (500934).

Assets: VPC Mechanical Services Building

Related Programs: N/A

Recommended Alternative Description

Scope of Work:
Demolish Mechanical Services building.
The asset in scope is the Mechanical Services Building located at 500 Consumers Road, North York, ON. The nature of work is the demolition of existing building.

Timing: The Project duration is 12 months:
0 – 4 months: Programming
4 - 6 months: Perming and Tender
6 – 12 months: Demolition and parking construction

Risks include contractor delays and material delivery delays or defects.

Expenditures:The total cost for the project is $0.55 M net capital which includes a working construction cost contingency of 15%. Construction costs are determined based on historical EGI project costs. The project costs are based on a Class 5 estimate.

Resources: External professional resources for design and engineering along with a construction company will be contracted for the project. Historically, EGI has retained architectural and engineering consulting services and general construction contractors for the execution of similar projects.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - Real Estate & Workplace Services - Furniture/Structures & Improvements
Investment Stage	Short Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	10 - Toronto
	Asset Program (EGI)	REWS - Furniture/Structures & Improvements
	Asset Class (EGI)	Real Estate & Workplace Services
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (5,430,811)	0.35	$ 9,000,000	1/1/2021

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 9,000,000	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ 550,000	$ -	$ -

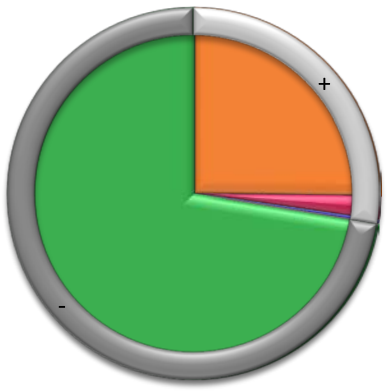
Investment Summary Report

Investment Code	Report Start Year	Number of Years
6087	2021	5

Investment Name

MSB Demolition & New Administrative Parking

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Cost Avoidance OPEX (CA)	2,903	25%
Energy Efficiency (CA)	238	2%
Avoided GHG Emissions (CA)	39	0%
Cost Avoidance CAPEX (CA)	0	0%
Budget Savings CAPEX (CA)	0	0%
Budget Savings OPEX (CA)	0	0%
Revenue Impact (CA)	0	0%
Total Investment Cost (CA)	(8,333)	72%
Total	**(5,154)**	**100%**

Investment Summary Report	Investment Code	Report Start Year	Number of Years
	3642	2021	5
	Investment Name: SMOC/Coventry Facility Consolidation		

Investment Description

Issue/Concern:

Coventry Road
The office building in Ottawa is an owned facility that is in physically fair condition. The facility's functionality is sound but there is excess space. In addition, the furniture and finishings do not meet functional standards. The office is in a good location to serve the respective area, but there is duplication in coverage between the SMOC and Coventry Road facilities.

Functional Obsolescence – Building: The acceptable EGI standard for the functional condition is 0, anything between 0 and 49% is considered correctable at the current location. The current facility Adequacy Index is 43%, considered marginally correctable at current location without consideration of other factors including adequacy of land size and the Functional Condition Index.

Functional Obsolescence – Site: The site does not meet operational requirements for size and vehicular circulation within the site. The yard size is smaller than EGI standard yard size requirements. The current yard size is 1.42 acres. EGI standard yard size is 2.5 acres. Building is in average condition and functionally sound (building has excess area). The site does not meet non-functional standards (furniture standards, finishes etc.) The site is in a good location but is no longer optimized for best use. There is potential for consolidation with the SMOC facility on 90 Bill Leatham Drive, Nepean, ON.

SMOC
SMOC is an owned facility in physically fair condition. The facility's functionality is sound, however, there is unused/excess space. In addition, the furniture and finishings do not meet non-functional standards (furniture standards, finishes etc.). The office is in a good location to serve its respective area, but there is duplication in coverage between this office and the office at Coventry Road.

Functional Obsolescence – Building: The acceptable EGI standard for the functional condition is 0. Anything between 0 and 49% is considered correctable at the current location. The current facility Adequacy Index is 24% which is considered correctable at the current location, without consideration of other factors including adequacy of land size and the Functional Condition Index.

Functional Obsolescence – Site: The configuration of site functions and circulation is inefficient and poses a safety hazard. The yard area is too small to meet current EGI standards. The building is in average condition and is functionally sound (building has excess area). The building does not meet non-functional standards (furniture standards, finishes etc.) It is in a good location but there is potential for consolidation with the Coventry Road facility.

Assets: 400 Coventry Road, Ottawa, ON, and 90 Bill Leatham Drive, Nepean, ON (SMOC)

Related Program: N/A

Recommended Alternative Description

Eastern Region Consolidated Facility Project
Scope of Work:
This project requires selling both the SMOC and Coventry Road properties, purchasing a property suitable in size (approx. 7 acres) and building a new 70,000 sq. ft. building that will consist of administration, warehouse, welding, and fabrication facilities. The assets in scope are located at 400 Coventry Road, Ottawa, ON, and 90 Bill Leatham Drive, Nepean, ON (SMOC). The nature of work is development of a new property and the construction and fit-up of a new building.

Solution Impact: This option corrects operational and workplace inefficiencies by consolidating SMOC and Coventry redundancies. The new facility will use less energy and emit less greenhouse gases. The service life for the new facility will be 25-40 years.

Timing: The total Project duration is 30 months:
0 – 3 months: Programming, design development, location analysis
3 – 6 months: Site acquisition
6 – 12 months: Site plan agreement, permit and tender documents, permit and tender process
12 – 14 months: Contract award and winter contingency as required
14 – 28 months: Construction
28 – 30 months: Fit-up and occupancy
Post-occupancy disposition of property

Risks include contractor delays and material delivery delays or defects.

Expenditures: The total cost for the project is $23.8M net capital which includes a working construction cost contingency of 15%. Construction costs are determined based on historical EGI project costs and land values using marketplace comparisons. The project also leverages national pricing agreements with furniture, walls, and flooring manufacturers. The project costs are based on a Class 5 estimate.

Resources: External professional resources for design and engineering along with a construction company will be contracted for the project. Historically, EGI has retained architectural and engineering consulting services and general construction contractors for the execution of similar projects.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - Real Estate & Workplace Services - Furniture/Structures & Improvements
Investment Stage	Short Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	60 - Ottawa
	Asset Program (EGI)	REWS - Furniture/Structures & Improvements
	Asset Class (EGI)	Real Estate & Workplace Services
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Investment Code	Report Start Year	Number of Years
3642	**2021**	**5**

Investment Summary Report

Investment Name

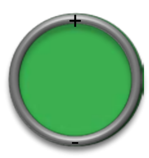
SMOC/Coventry Facility Consolidation

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (26,288,707)	0.00	$ 30,825,000	1/1/2021

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 8,000,000	$ 12,000,000	$ 10,825,000	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ 350,000	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(26,289)	100%
Total	**(26,289)**	**100%**

ENBRIDGE **Investment Summary Report**	Investment Code **3640**	Report Start Year **2021**	Number of Years **5**
	Investment Name Station B New Building		

Investment Description

Issue/Concern:
The Station B office on Eastern Avenue is an owned property in a good location, but does not meet current building standards or operational requirements. The physical condition is considered good, but the utilization and functionality is challenged. The office space no longer meets the needs of the staff currently working out of the facility. The new building will be able to provide the needed functionality and safety for the staff to carry out their tasks.

Physical Obsolescence: The acceptable EGI standard for the physical condition is a Facility Condition Index (FCI) of 0 to 5%. The current FCI of the facility based on this study is 12.28%. Therefore, the physical condition of the facility does not meet EGI acceptable standards.

Functional Obsolescence – Building: The acceptable EGI standard for the functional condition is 0. A functional condition between 0 and 49% is considered correctable at the current location. The current facility Adequacy Index (AI) is 49%.

Functional Obsolescence – Site: The property is divided into two separate parts. The first part consists of approximately 0.7 acres completely fenced off, including a secure gate station located adjacent to the site on the northwest corner. The reminder of the site consists of 3.2 acres and is used as an operations depot. The site does not meet operational requirements for size and vehicular circulation. One point of access is provided to the site which poses circulation difficulties and poses operational inefficiencies. The yard size is marginally smaller than EGI standard yard size requirements. The current yard size is 2.25 acres. The EGI standard yard size is 2.5 acres. It was noted by EGI staff that the existing yard size is adequate for current operations. The existing building requires expansion by approximately 8,000 square feet to meet the need for current staff and EGI functional requirements.

Asset: 405 Eastern Avenue, Toronto, ON.

Related Program: N/A

Recommended Alternative Description

Scope of Work: The project entails demolishing the existing facility and building a new single storey building with underground parking to ensure much needed yard requirements for core operational needs such as fleet and equipment parking, aggregate bunkers, and yard. Underground parking will ensure the site is maximized for operations yard needs as land in Toronto's downtown is limited and requires efficient use of property. This will expand the usable existing yard. The new building footprint of approximately 20,000 square feet will ensure adequate interior storage/warehouse and fabrication space for operations, an operations muster/meeting space, washroom/ locker facilities appropriately sized for the operation, and and a larger office environment for site staff. The program will include currently missing elements such as a lunch room and meeting rooms. This new facility will correct operational and workplace inefficiencies, using less energy and emitting less greenhouse gases. The assets in scope are located at 405 Eastern Avenue, Toronto, ON. The nature of work is site improvements and construction and fit-up of a new building.

Solution Impact: The service life of the new facility would be 25-40 years, with the old building being demolished.

Project Timing: The project duration is 36 months.

0-3 months: Programming and design development
3-9 months: Site plan agreement, permit and tender documents
9-12 months: Permit and tender process
12-14 months: Contract award and winter contingency as required
14-28 months: Construction
28-30 months: Fit-up and occupancy
30-36 months: Old building demolition and remaining site improvements

Risks include contractor delays and material delivery delays or defects.

Expenditures: The total cost for the project is $6.5 M net capital which includes a working construction cost contingency of 15%. Construction costs are determined based on historical EGI projects. The project also leverages national pricing agreements with furniture, walls, and flooring manufacturers. Project costs are based on a Class 5 estimate.

Resources:
Professional resources for design and engineering along with a contractor will be retained from the marketplace. Historically, EGI has engaged architectural and engineering consulting services and general construction contractors for the execution of similar projects.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - Real Estate & Workplace Services - Furniture/Structures & Improvements
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	10 - Toronto
	Asset Program (EGI)	REWS - Furniture/Structures & Improvements
	Asset Class (EGI)	Real Estate & Workplace Services
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Investment Summary Report

Investment Code	Report Start Year	Number of Years
3640	2021	5

Investment Name

Station B New Building

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 2	Recommended	$ (15,851,852)	0.00	$ 17,600,000	1/1/2019

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 15,500,000	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ 350,000	$ -	$ -	$ -	$ -

Alternative Value - Recommended

Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(15,852)	100%
Total	**(15,852)**	**100%**

Investment Code	Report Start Year	Number of Years
8782	**2021**	**5**

ENBRIDGE

Investment Summary Report

Investment Name

VPC Core and Shell

Investment Description

Issue/Concern: The building shell and core for the VPC facility is over 50 years old. The tower building was constructed in or around 1968 as a two-storey building with an addition in 1978 that included floors 3 to 5. The VPC facility houses over 1,200 employees. It is an owned facility that is currently undergoing renovations.

Physical condition: Currently safe, ongoing periodic structural review required.

Functional condition: Failed performance as an insulator and barrier to the outdoors, water and vapor intrusion, comfort & energy efficiency is compromised.

Proposed activity: Envelope replacement - high performance curtain wall, new shell with very high levels of glazing allowing increased daylight and views; change from 30% today to 60-80% penetration of light.

Asset: 500 Consumers Road, North York, ON

Related Program:N/A

Recommended Alternative Description

Scope of Work: The assets in scope are located at 500 Consumers Road, North York, ON. The nature of work is the removal and replacement of the 50 year old exterior envelope on the tower and the replacement of core mechanical and electrical systems. This project calls for correcting physical and functional deficiencies by renovating and renewing the existing facility. This is the preferred strategy since the FCI and AI indices show the building and site deficiencies are correctable by the following activities:
-Renewing the building's main mechanical system
-Adding two elevators
-Renovating the 3 main staircases
-Replacing the building envelope

Solution impact: The renovation will correct operational and workplace inefficiencies by using less energy and emitting less greenhouse gases on the existing property. The service life of the renewed facility would be 40 years.

Timing: The project duration is 24 months:
0 – 3 months: Programming and design development
3 – 9 months: Permit and tender documents
9 – 12 months: Permit and tender process
12 – 14 months: Contract award and winter contingency as required
14 – 24 months: Construction

Risks include contractor delays and material delivery delays or defects.

Expenditures: The total cost for the project is $20M net capital. Construction costs are determined from facility assessment reports and architectural consultant budget forecasts and use marketplace comparisons. Project costs are based on a Class 5 estimate.

Resources: External professional resources for design and engineering as well as a construction company will be contracted for the project. Historically, EGI has retained architectural and engineering consulting services and general construction contractors for the execution of similar projects.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - Real Estate & Workplace Services - Furniture/Structures & Improvements
Investment Stage	Short Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	00 - Head Office
	Asset Program (EGI)	REWS - Furniture/Structures & Improvements
	Asset Class (EGI)	Real Estate & Workplace Services
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (11,965,850)	0.15	$ 20,000,000	1/1/2024

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ -	$ -	$ -	$ 10,000,000	$ 10,000,000
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ 1,000,000	$ 1,000,000

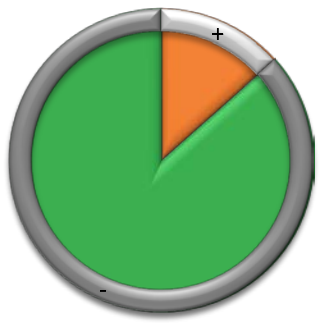
Investment Summary Report

Investment Code	Report Start Year	Number of Years
8782	2021	5

Investment Name

VPC Core and Shell

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Cost Avoidance OPEX (CA)	2,190	13%
Cost Avoidance CAPEX (CA)	0	0%
Budget Savings CAPEX (CA)	0	0%
Budget Savings OPEX (CA)	0	0%
Revenue Impact (CA)	0	0%
Total Investment Cost (CA)	(14,156)	87%
Total	**(11,966)**	**100%**

ENBRIDGE **Investment Summary Report**	Investment Code **3634**	Report Start Year **2021**	Number of Years **5**
	Investment Name VPC-1		

Investment Description

Issue/Concern:
The VPC facility is the largest EGI administrative facility. It is an owned facility that is currently undergoing renovations to address the physical condition and capacity concerns, as well as to replace legacy furniture and finishings. The first floor has not yet been renovated.

Physical Obsolescence: The acceptable EGI standard for the physical condition is a Facility Condition Index (FCI) of 0 to 5%. The current FCI of the facility based on this study is 5.59%. Therefore, the physical condition of the facility does not meet EGI acceptable standards.

Functional Obsolescence – Building: The acceptable EGI standard for the functional condition is 0. A functional condition between 0 and 49% is considered correctable at the current location. The current facility Adequacy Index (AI) is 11% which is considered correctable at the current location, without consideration of other factors including adequacy of land size and the FCI.

Functional Obsolescence – Site: The site area and parking provided are generally in compliance with EGI requirements.

Asset: First Floor, 500 Consumers Road Toronto, ON.

Related Program:N/A

Recommended Alternative Description

Scope of Work:The assets in scope are the first floor at 500 Consumers Road Toronto, ON. The nature of work is interior renovation and furnishings. The project corrects physical and functional deficiencies on the first floor of the tower by renovating and renewing the existing space. The current site has capacity to meet EGI functional requirements. Renovations to the building will correct operational and workplace inefficiencies, using less energy and emitting less greenhouse gases.

Solution Impact: The interior renovation will extend the asset useful life by 10 to 15 years.

Timing and Execution Risks:
The total project duration is 14 months and broken down as follows:
0 – 2 months: Programming and design development
2 – 5 months: Permit and tender documents
5 – 7 months: Award, permit and tender process
7 – 12 months: Construction
12 – 14 months: Fit-up and occupancy

Risks include contractor delays and material delivery delays or defects.

Expenditures:
The total cost for the project is $4.2M net capital which includes a working construction cost contingency of 15%. Construction costs are determined based on historical EGI project costs and land values are determined using marketplace comparisons.
The project also leverages national pricing agreements with furniture, walls, and flooring manufacturers. The project costs are based on a Class 5 estimate.

Resources:
External professional resources for design and engineering along with a construction company will be contracted for the project. Historically, EGI has retained architectural and engineering consulting services and general construction contractors for the execution of similar projects.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - Real Estate & Workplace Services - Furniture/Structures & Improvements
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	10 - Toronto
	Asset Program (EGI)	REWS - Furniture/Structures & Improvements
	Asset Class (EGI)	Real Estate & Workplace Services
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	Building Code improvements such as OADA compliance and Fire code compliance.
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

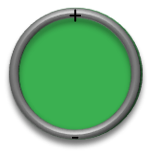
Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (5,925,926)	0.00	$ 7,950,000	1/1/2019

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 3,700,000	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ 350,000	$ -	$ -	$ -	$ -

Investment Summary Report	Investment Code	Report Start Year	Number of Years
	3634	2021	5
	Investment Name: VPC-1		

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(5,926)	100%
Total	**(5,926)**	**100%**

Fleet and Equipment

	Investment Code	Report Start Year	Number of Years
ENBRIDGE **Investment Summary Report**	49980	2021	5
	Investment Name: 2021 - 485 Heavy Work Equipment		

Investment Description

Issue/concern: In the EGD rate zone, heavy work equipment units which are much older and worn need to be replaced. Individual equipment is assessed using the Fleet Flagship Replace application.

Asset: Various Heavy Duty Equipment assets.

Related Program: N/A

Recommended Alternative Description

Scope of work: This Project provides EGI with the necessary heavy work equipment to safely and efficiently run business operations in the EGD rate zone. The goal is to maintain the integrity of all heavy work equipment assets for safe and reliable operation. To help achieve this goal, the Fleet department utilizes financial cost, risk analysis, and physical assessment information to drive replacement decisions. As the equipment ages and exceeds its useful life threshold, it can become an operational safety concern. Additionally, there are increases in maintenance costs and operational downtime which affects overall productivity.

Resources: Fleet and Equipment staff

Solution Impact: The fleet management analytical software tool Flagship Replace is used to make informed replacement decisions for rolling equipment such as backhoes. Replacement decisions for non-rolling equipment (i.e. welders) are primarily based on age, hour meter, and physical condition. Once heavy equipment assets reach an age of 10 years, a physical assessment is conducted to evaluate the equipment. A comparison of the maintenance history is used to determine refurbish or replace decisions.

Project Timing and Execution risks: Assets are ordered in January or February of fiscal year and delivered by December 31. Risk - delivery of assets not met by the December 31 deadline.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - Fleet & Equipment - Equipment & Materials
Investment Stage	Short Term Planning		

Investment Overview

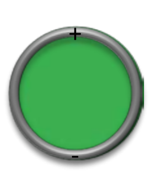
1. Project Information	State/Province	Ontario
	Operating Area (EGI)	00 - Head Office
	Asset Program (EGI)	FLEET - Equipment & Materials
	Asset Class (EGI)	Fleet & Equipment
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	Yes

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (2,902,963)	0.00	$ 3,135,200	1/1/2021

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 3,135,200	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(2,903)	100%
Total	**(2,903)**	**100%**

Investment Summary Report

Investment Code	Report Start Year	Number of Years
49978	2021	5

Investment Name

2021- 484 Light and Medium duty vehicles

Investment Description

Issue/Concern: In the EGD rate zone, light and medium duty vehicles are required to replace existing vehicles that are in poor operating condition.

Asset: Light duty vehicles and medium duty vehicles.

Related Program: N/A

Recommended Alternative Description

Scope of Work: This project provides EGI with the necessary fleet vehicles to safely and efficiently run its business operations in the EGD rate zone. The goal of the project is to maintain the integrity of all fleet assets for safe and reliable operation. This ongoing replacement strategy optimizes the asset life cycle, improves safety, and reduces risk for EGI and its employees. To help achieve this goal, Fleet utilizes financial cost analysis, risk analysis, and physical asset assessment to guide replacement decisions.

Resources: Fleet and Equipment staff

Solution Impact: In order to replace aging fleet assets, a report is generated by the fleet management analytical software tool Flagship Replace which uses raw fleet data to identify all vehicles meeting the replacement criteria. The direct impact is reduced O&M repair and maintenance costs, and improved driver safety.

Project Timing and Execution Risks: Assets are ordered in January or February of fiscal year and delivered by December 31. Risk - delivery of assets not met by the December 31 deadline.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - Fleet & Equipment - Vehicles
Investment Stage	Short Term Planning		

Investment Overview

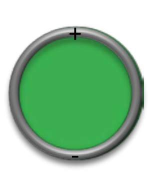
1. Project Information	State/Province	Ontario
	Operating Area (EGI)	01 - All
	Asset Program (EGI)	FLEET - Vehicles
	Asset Class (EGI)	Fleet & Equipment
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	Yes

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (4,504,444)	0.00	$ 4,864,800	1/1/2021

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 4,864,800	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(4,504)	100%
Total	**(4,504)**	**100%**

Technology and Information Services

Investment Summary Report	Investment Code	Report Start Year	Number of Years
	101362	2021	5
	Investment Name: IT - 00 - Microsoft Enterprise Agreement 2021		

Investment Description

Issue/Concern: This is a contractual agreement with Microsoft that must be honoured. Three year Microsoft Enterprise Agreements are required to be able to continue using the Microsoft suite at EGI: Office, Outlook, SharePoint, Skype, etc.

Assets: TIS Software - packaged

Related Program: N/A

Recommended Alternative Description

Scope of Work:
This project is the annual payment of the Microsoft Enterprise Agreement (EA). The EA provides "software assurance" which allows us to upgrade EGI's Microsoft license assets as new versions of the software are released by Microsoft without additional cost. The EA is a three-year agreement. A payment is due in each of the three years based on the licensed assets owned by Enbridge at the beginning of the agreement. True-up payments are also made annually as new licensed assets are acquired, and are covered in this project. Contractual obligations and use of the software assets in the calendar year require payment in that year.

Resources:
This is a procurement project only, performed by Enbridge TIS, typically executed in February (payment) and December (true-up).

Solution impact: Allows for the usage of the Microsoft suite of products used by Enbridge users throughout the organization.

Timing and execution risk: if this spend is not executed, Enbridge would not be able to utilize some products, upgrade any of the products, and would likely be in violation of the license agreement if we are unable to true up based on actual usage

Benefits:
Microsoft EA allows for the use of the Microsoft licensed assets which include email, calendaring, servers etc... Essentially, this project allows for EGI personnel to use the Microsoft suite of products, which are key productivity tools, and to upgrade to current versions without re-purchasing the licensing. Products included are: Outlook, Word, Excel, PowerPoint, OneNote, Access, Publisher, Teams, Skype, Project, Visio, Windows operating system and various utilities that come with the operating system.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - TIS - TIS Infrastructure
Investment Stage	Short Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	00 - Head Office
	Asset Program (EGI)	TIS Infrastructure
	Asset Class (EGI)	TIS
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	Yes

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (1,944,444)	0.00	$ 2,100,000	1/1/2021

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 2,100,000	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended

Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(1,944)	100%
Total	**(1,944)**	**100%**

ENBRIDGE Investment Summary Report	Investment Code	Report Start Year	Number of Years
	8602	**2021**	**5**
	Investment Name: Operation Digital		

Investment Description

Issue/Concern: This project is to provide a solution for digitizing the Engineering standards documents,implementing software and developing a solution that will improve accessibility and consistency of records, resulting in :
-Ensuring that engineering documents (policies, procedures, standards, and processes) are compliant to both regulatory and standards that follow process safety policies and have well-defined procedures as it pertains to work on EGI assets.
-Reducing costs in creating, maintaining, and delivery of engineering documents while still remaining compliant. -Improving the readability of engineering documents so that they can be more easily understood and followed in order to reduce safety incidents. Improve the overall delivery and consumption of engineering document content to both internal and external EGI stakeholders.
-Establishing a governance structure so that engineering documents are kept up to date and meet regulatory standards and compliance.

Asset: TIS - Software - Packaged

Related Program: N/A

Recommended Alternative Description

Scope of Work:
The solution would include tools to perform the transformation of engineering documentation into a reusable format that is easy to update and with a consistent look and feel. In addition, the new engineering content framework will require a publishing mechanism to allow for consumption of the content in various situations faced by Operations personnel. The target audience also includes Extended Alliance partners.
Approach: Standard TIS project management approach, including a signed charter and approved project plan for each calendar year, encompassing the design, build, test and implementation phases.
Resources: TIS PM, BA, data architect, developers/support analysts and QA personnel.

Solution impact: This solution is of significant benefit to the Engineering department, and will help ensure safe and reliable operations of field workers.

Timing and execution risk: 2021 is the third year of this three-year project and if it is not executed then the benefits, which are significant, will not be realized.
2020: Funding requirements lowered from $3M to $1.5M. Primary driver for the reduction was a change in solution approach and utilizing a third party vendor that significantly reduced the costs associated with the documentation digitization.

Benefits: Avoided Printing Costs:
- In 2013 C&M Manuals - $235K into 1,500 pages to get the approximate cost per page: $156 + 15% Xerox markup = $180 per printed page.
- Assume 15,000 pages in the E&AM library in total but assume only 60% of that is printed.
- 9,000 pages x $180/pp = $1.62M. Even if we only print half of the total library it's still a $1.35M in savings
- Separate exercise with Xerox to look at what Engineering printed manuals, forms, etc. which verified the $1.35M approximate number:
2018 – 230K
2019 – 600k
2020 – 1.13 Million

Soft Benefits:
- Documentation to use unique procedural titles that communicate purpose, due to the related topics bread crumb
- Content is clear and at the right level of detail (involves rewriting documents to an audience-oriented standpoint)
- Tasks are assigned to the appropriate individual for procedures involving multiple operators.
- Consistent procedure format (using the DITA framework, all procedures would be consistently updated as changes to a procedure that affects multiple documents can be applied globally once the documentation set is republished).
- Overviews for lengthy procedures or activities involving multiple procedures (structured authoring enables consistency)
- Procedure documentation can be enhanced with interactive images, diagrams, or videos (a limitation of print media)
- Provision of accurate timely documents and data to the business (having one source of truth, with updates disseminated consistently to stakeholders). The proposed solution makes it easier to update content and publish content online.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - TIS - TIS Business Solutions
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	00 - Head Office
	Asset Program (EGI)	TIS Business Solutions
	Asset Class (EGI)	TIS
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

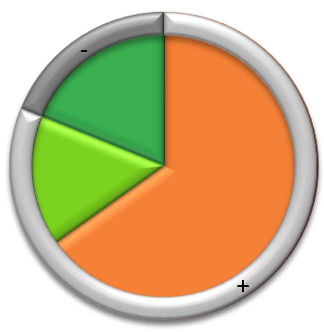
ENBRIDGE Investment Summary Report	Investment Code: 8602	Report Start Year: 2021	Number of Years: 5
	Investment Name: Operation Digital		

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ 10,232,705	4.30	$ 4,090,000	1/1/2019

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 2,000,000	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Cost Avoidance OPEX (CA)	10,709	65%
Budget Savings OPEX (CA)	2,625	16%
Cost Avoidance CAPEX (CA)	0	0%
Budget Savings CAPEX (CA)	0	0%
Revenue Impact (CA)	0	0%
Total Investment Cost (CA)	(3,102)	19%
Total	**10,233**	**100%**

Growth

Investment Summary Report

Investment Code	Report Start Year	Number of Years
100203	2021	5

Investment Name

Customer Stratford Reinforcement

Investment Description

Issue/Concern/Opportunity:
In order to support a significant load addition on the Forest, Hensall and Goderich Transmission System, a reinforcement is required from the end of the 2019 Stratford Reinforcement project to the inlet of Stratford Gate Station (17P-301).
This project allows EGI to continue to provide regular rate customers with gas while also serving a new glass plant with a known demand of 18,000 m3/h.

Justification: Reinforcement is required to add customer (a Glass plant) to the system.

Assets: This project will consist of two components:
1. Approximately 9.4 kilometres of NPS 12 high pressure transmission (6160 kPa MOP) steel natural gas main extending from the end of the Stratford Reinforcement Phase 1 project at Perth-Oxford Road and into Stratford Gate Station (along Crane Avenue).
2. Approximately 1 kilometre of NPS 6 (3450 kPa MOP) and approximately 700 metres of NPS 4 (3450 kPa MOP) heading south along Erie Street (Hwy 7) to the customer site at Erie and 29 Line.

Related Programs: N/A

Recommended Alternative Description

Scope of Work: Approximately 9.4 kilometres of NPS 12 high pressure transmission (6160 kPa MOP) steel natural gas main extending from the end of the Stratford Reinforcement Phase 1 project at Perth-Oxford Road and into Stratford Gate Station (along Crane Avenue).
Approximately 1 kilometre of NPS 6 (3450 kPa MOP) and approximately 700 metres of NPS 4 (3450 kPa MOP) heading south along Erie Street (Hwy 7) to the customer site at Erie and 29 Line.

Resources: Company crews, contractor labour and third-party vendor suppliers

Solution Impact: This reinforcement project will ensure the system has adequate flow capacity in anticipation of projected customer growth.

Project Timing and Execution Risk: Construction start March 2021- customer requires gas by April 2022.
Risks: Weather impacts, resource availability, procurement issues, etc.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Growth - System Reinforcement
Investment Stage	Short Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_04 - London
	Asset Program (EGI)	GTH - System Reinforcement
	Asset Class (EGI)	Growth
2. Compliance	Compliance Investment	
	Compliance Justification & Code	
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Perth Road 113	Recommended	$ (12,109,054)	0.00	$ 13,300,000	1/1/2021

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 10,300,000	$ 23,900,000	$ -	$ -	$ -
Contributions	$ -	$ (20,900,000)	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended

Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(12,109)	100%
Total	**(12,109)**	**100%**

Investment Code	Report Start Year	Number of Years
48757	**2021**	**5**

Investment Summary Report

Investment Name

HAMI: Dunnville Line Reinforcement (6.3 km of NPS 10)

Investment Description

Issue/Concern: Reinforcement projects broadly involve the installation of new or modification of existing gas distribution assets to maintain minimum required system pressure, maintain capacity, and meet customer demand. These projects are primarily driven by customer growth and system reliability considerations. Failure to implement reinforcement projects in a timely manner could lead to a potential inability to support increasing demands of existing customers and the addition of future customers.

System Reinforcement - Loop 10" reinforcement from outlet of Caledonia Trans, ending at Stoneman Road

Assets: 6.3 kilometres of NPS 10 outlet of Caledonia Trans, ending at Stoneman Road

Related Program: N/A

Recommended Alternative Description

Scope of Work: 8100 kilometres 10" ST in road allowance (yellow line) From Caledonia Station, north on Highway 6, west on Haldibrook Road, south on Abbey Road, running through easement to 10" loop.

Resources: Company crews, contractor labour and third-party vendor suppliers.

Solution Impact: This reinforcement project will ensure the system has adequate flow capacity in anticipation of projected customer growth.

Project Timing and Execution Risks: Weather impacts, resource availability, procurement issues, etc.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Growth - System Reinforcement
Investment Stage	Short Term Planning		

Investment Overview

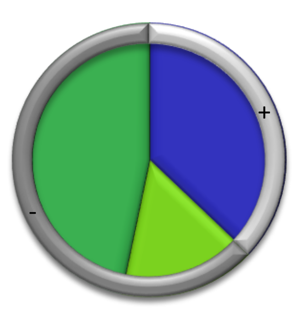
1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_16 - Hamilton
	Asset Program (EGI)	GTH - System Reinforcement
	Asset Class (EGI)	Growth
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (4,337,382)	0.45	$ 9,100,000	1/1/2021

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 600,000	$ 8,500,000	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Revenue Impact (CA)	6,228	37%
Financial Risk	0	0%
Public Safety Risk	0	0%
Budget Savings OPEX (CA)	(2,722)	16%
Total Investment Cost (CA)	(7,843)	47%
Total	**(4,337)**	**100%**

Investment Summary Report

Investment Code	Report Start Year	Number of Years
49774	2021	5

Investment Name

LOND: Goderich Transmission System, Reinforcement (11.4km of NPS 10)

Investment Description

Issue/concern: System Reinforcement: Reinforcement projects broadly involve the installation of new or modification of existing gas distribution assets to maintain minimum required system pressure, maintain capacity, and meet customer demand. These projects are primarily driven by customer growth and system reliability considerations. Failure to implement reinforcement projects in a timely manner could lead to a potential inability to support increasing demands of existing customers and the addition of future customers.

Assets: 11.4 kilometres of NPS 10 pipe

Related Programs: N/A

Recommended Alternative Description

Scope of Work: Loop existing NPS 8 Goderich Transmission pipeline with new NPS 10 steel pipeline (see red route) for 11.4 kilometres in road allowance of Huron Road (County Rd 8) from Hensall Road Valve Site to new Sanctuary Road.

Resources: Company crews, contractor labour and third-party vendor suppliers.

Solution Impact: This reinforcement project will ensure the system has adequate flow capacity in anticipation of projected customer growth.

Project Timing and Execution Risks: Weather impacts, resource availability, procurement issues, etc.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Growth - System Reinforcement
Investment Stage	Long Term Planning		

Investment Overview

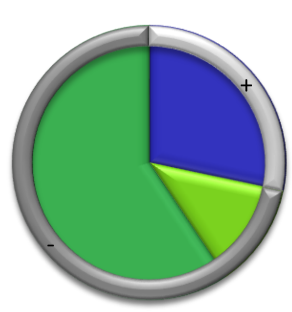
1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_04 - London
	Asset Program (EGI)	GTH - System Reinforcement
	Asset Class (EGI)	Growth
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (11,557,680)	0.27	$ 25,000,000	1/1/2024

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ -	$ -	$ -	$ 67,341	$ 2,170,347
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Revenue Impact (CA)	7,539	28%
Financial Risk	0	0%
Public Safety Risk	0	0%
Budget Savings OPEX (CA)	(3,275)	12%
Total Investment Cost (CA)	(15,821)	59%
Total	**(11,558)**	**100%**

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
49004	2021	5

Investment Name

LOND: Upgrade Byron Transmission Stn (13N-501) Reinforcement

Investment Description

Issue/Concern:
The Byron Transmission Station Rebuild Project is required as a result of the rapid growth on the south and west sides of the London System which are supplied gas from the Byron Transmission Station. Due to the growth interest in markets fed by Byron Transmission Station and the abandonment of the London Lines, the Byron Transmission Station is projected to reach capacity in 2022.

Assets: Byron Transmission Station

Related Programs: N/A

Recommended Alternative Description

Scope of Work: The Byron Transmission Station Rebuild Project is required as a result of the rapid growth on the south and west sides of the London System which are supplied gas from the Byron Transmission Station. Due to the growth interest in markets fed by Byron Transmission Station and the abandonment of the London Lines, the Byron Transmission Station is projected to reach capacity in 2022.

Resources: Company crews, contractor labour and third-party vendor suppliers.

Solution Impact: This reinforcement project will ensure the system has adequate flow capacity in anticipation of projected customer growth.

Project Timing and Execution Risks: Scheduled to be energized and brought into service in 2021
Risks: Weather impacts, resource availability, procurement issues, etc.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Growth - System Reinforcement
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_04 - London
	Asset Program (EGI)	GTH - System Reinforcement
	Asset Class (EGI)	Growth
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (7,953,704)	0.00	$ 8,550,000	1/1/2020

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 8,050,000	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended

Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(7,954)	100%
Total	**(7,954)**	**100%**

Investment Summary Report

Investment Code	Report Start Year	Number of Years
49796	2021	5

Investment Name

LOND: Upgrade Ingersoll Trans (14R-102) Reinforcement

Investment Description

Issue/Concern: A rebuild of the Ingersoll Transmission Station (14R-102) is required due to inadequate capacity and will allow in-franchise growth on the Eastern Transmission System serving communities like Tillsonburg and Woodstock.

Assets: Ingersoll Transmission Station (14R-102)

Related Programs: N/A

Recommended Alternative Description

Scope of Work:
Complete station rebuild is required as the station is showing signs of wearing and load growth in the area is expected to exceed station capacity.

Resources: Capital Development with be managing this project. Company crews, contractor labour and third-party vendor suppliers will be used to complete the work.

Solution Impact:
Without the rebuild, low pressure downstream of the station could result in a loss of customers on peak winter days.

Project Timing and Execution Risks:
The project is to be completed by Nov. 2022
Weather impacts, resource availability, procurement issues, etc

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Growth - System Reinforcement
Investment Stage	Long Term Planning		

Investment Overview

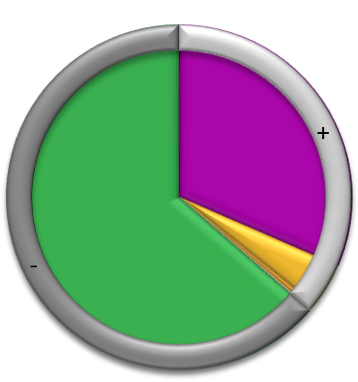
1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_04 - London
	Asset Program (EGI)	GTH - System Reinforcement
	Asset Class (EGI)	Growth
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (7,210,219)	0.00	$ 8,370,000	1/1/2021

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 500,000	$ 7,870,000	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Financial Risk	3,571	32%
Operational Risk	475	4%
Environmental Risk And Remediation	57	1%
Reputational Risk	11	0%
Employee And Contractor Safety Risk	0	0%
Public Safety Risk	0	0%
Total Investment Cost (CA)	(7,210)	64%
Total	**(3,095)**	**100%**

ENBRIDGE Investment Summary Report	Investment Code 49116	Report Start Year 2021	Number of Years 5
	Investment Name: NBAY: Parry Sound Lateral Reinforcement (12.5 km of NPS 6)		

Investment Description

Issue/Concern:
Reinforcement projects broadly involve the installation of new or modification of existing gas distribution assets to maintain minimum required system pressure, maintain capacity, and meet customer demand. These projects are primarily driven by customer growth and system reliability considerations. Failure to implement reinforcement projects in a timely manner could lead to a potential inability to support increasing demands of existing customers and the addition of future customers.

Description: Reinforcement project required due to the increased demand within the Parry Sound area. Residential and Industrial additions have currently accounted for most of the NPS 4 pipeline capacity since being installed in 1998 (the original OEB filing was for a 10-year life span). The 1998 forecasted and observed attachments align, the exception being the commercials which have been larger than forecasted. The 2015-16 FBP forecast suggested 12 commercials per year attaching. The Crofters load addition was equivalent to 41 such commercials in 1 year. The current system can only handle a total flow of ~4500 m3/h, and if the lateral was fully 6", it could handle ~12500 m3/h of flow. This increased flow capacity will ensure the system will continue to meet future growth demands, specifically future residential attachments, the identified industrial park in Seguin, and the potential future expansion if the McDougall community.
Assets: Parry Sound Lateral - 12. 5 kilometres of NPS 6 pipe.

Related Programs: N/A

Recommended Alternative Description

Scope of Work: 12.5 kilometres main to be installed alongside existing 4" main to increase flows into Parry Sound. Alternatives to this project have not yet been fully vetted but are planned to be reviewed by the end of 2020.

Resources: Company crews, contractor labour and third-party vendor suppliers.

Solution Impact: Increased flow capacity will ensure the system will continue to meet future growth demand. The network adds about 100 customers per year - without the reinforcement customers would not be able to be added in violation of EBO 188.

Project Timing and Execution Risks: This project is scheduled to be in service in 2023. Risks: Weather impacts, resource availability, procurement issues, etc.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Growth - System Reinforcement
Investment Stage	Long Term Planning		

Investment Overview

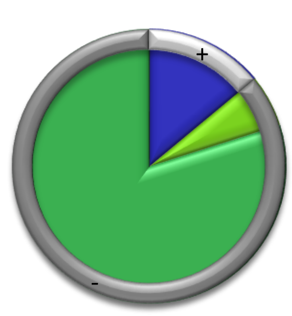
1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_46 - North Bay & Orillia
	Asset Program (EGI)	GTH - System Reinforcement
	Asset Class (EGI)	Growth
2. Compliance	Compliance Investment	
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (10,730,406)	0.10	$ 15,000,000	1/1/2023

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ -	$ -	$ 15,000,000	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Revenue Impact (CA)	2,089	14%
Financial Risk	0	0%
Public Safety Risk	0	0%
Budget Savings OPEX (CA)	(912)	6%
Total Investment Cost (CA)	(11,907)	80%
Total	**(10,730)**	**100%**

Investment Summary Report

Investment Code	Report Start Year	Number of Years
49793	2021	5

Investment Name

SUDB: Marten River Compression, Reinforcement

Investment Description

The Sudbury system is supported by the Liquefied Natural Gas (LNG)/compressor facility at Hagar. However, the volume of LNG available is insufficient to maintain the system in the event a historical cold winter is experienced. Higher than contracted pressures from TC Energy would be required to offset LNG utilization. This proposed reinforcement project includes the addition of two 2100 HP compressors at Marten River to increase system pressures to support Sudbury system demand. However, alternatives are continuing to be assessed - alternatives include a lift and lay pipeline project from North Bay and upgrades at the Hagar LNG plant.

Assets: 2x 2100 HP compressors

Related Programs: N/A

Recommended Alternative Description

Scope of Work:
Option A: 2x 2100 HP Compressors at Marten River
Option B: Transmission Reinforcement plus compression
Option C: Lift and lay pipeline from North Bay.
Option D: Upgrade the Hagar LNG facility.

Resources: Company crews, contractor labour and third-party vendor suppliers

Solution Impact:This reinforcement project will ensure the system has adequate flow capacity in anticipation of projected customer growth. Any of the options prevents a loss of customer if TCPL delivers tariff minimum inlet pressures - 15,000 customers could be lost on peak day if the reinforcement is not complete.

Project timing and Execution Risks: Scheduled to be in service in 2023.
Risks: Weather impacts, resource availability, procurement issues, etc.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Growth - System Reinforcement
Investment Stage	Long Term Planning		

Investment Overview

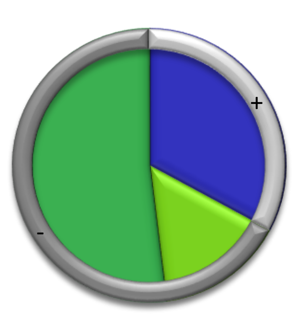
1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_43 - Sudbury & S.S. Marie
	Asset Program (EGI)	GTH - System Reinforcement
	Asset Class (EGI)	Growth
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (27,030,191)	0.34	$ 51,600,000	1/1/2023

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ -	$ -	$ 51,600,000	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Revenue Impact (CA)	25,903	33%
Financial Risk	0	0%
Public Safety Risk	0	0%
Budget Savings OPEX (CA)	(11,971)	15%
Total Investment Cost (CA)	(40,962)	52%
Total	**(27,030)**	**100%**

Enbridge Investment Summary Report	Investment Code	Report Start Year	Number of Years
	49925	2021	5
	Investment Name		
	THUN: Greenstone Mine, Geraldton (12km of NPS 6)		

Investment Description

Issue/Concern:
Reinforcement projects broadly involve the installation of new or modification of existing gas distribution assets to maintain minimum required system pressure, maintain capacity, and meet customer demand. These projects are primarily driven by customer growth and system reliability considerations. Failure to implement reinforcement projects in a timely manner could lead to a potential inability to support increasing demands of existing customers and the addition of future customers.

-12 kilometres of NPS 6 plus TBS (Town Border Station) and SMS (Sales Metering Station) installation
-Customer driven and funded: 1 customer (Mine) Compliance under EBO 188

Assets: 12 kilometres of NPS 6 pipe

Related Programs: N/A

Recommended Alternative Description

Scope of Work: Install ~ 12 kilometres of NPS 6 pipe from the Geraldton TBS (at the existing TransCanada tap) to the customer's site. The majority of pipe will be installed on the current and old Hwy 584 and will require a new customer station and modifications to the existing Geraldton TBS.

Resources: Company crews, contractor labour and third-party vendor suppliers

Solution Impact:This reinforcement project will ensure the system has adequate flow capacity in anticipation of projected customer growth.

Project Timing and Execution Risks: This project is scheduled to be in service in 2021.
Risks: Weather impacts, resource availability, procurement issues, etc.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Growth - System Reinforcement
Investment Stage	Executing		

Investment Overview

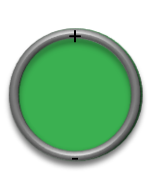
1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_54 - Head Office Support
	Asset Program (EGI)	GTH - System Reinforcement
	Asset Class (EGI)	Growth
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (3,654,630)	0.00	$ 3,907,000	1/1/2020

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 3,407,000	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(3,655)	100%
Total	**(3,655)**	**100%**

Investment Code	Report Start Year	Number of Years
103275	2021	5

ENBRIDGE

Investment Summary Report

Investment Name

TIMM: Macassa Mine New Shaft #3 SMS

Investment Description

Issue/Concern:
Macassa Mine (contract customer Kirkland Lake Gold) in Kirkland Lake is requesting additional load to mine Shaft #3. It has been identified by Network Analysis that the additional firm contract load requires reinforcement on the existing NPS 4 Kirkland Lake transmission line fed from Kenogami CMS (42501001). The additional load also triggers a new NPS 4 HP service to Shaft #3 and a new NPS 2 HP main installed to Shaft # 4. Stations engineering has identified approximate standard designs for shaft #3: 9.S 210 HP.

This project includes a new NPS 4 HP customer service and requires first stage cut at HWY 66 (48.122424, -80.083232) and runs along unnamed customer access road @ 1900 kPa MOP.

The tentative in-service date for the new SMS at Shaft #3 is November 1, 2021, as of May 2020.

Assets: Station ID 12500030 (station ID developed for the new Shaft #3 SMS)

Related Investments: C55 investment #103278 pertains to the new SMS at Shaft #4, also with a tentative date of November 1, 2021.

Recommended Alternative Description

Scope of Work: This project includes a new NPS 4 HP customer service. Requires first stage cut at HWY 66 (48.122424, -80.083232) and runs along unnamed customer access road @ 1900 kPa MOP. The tentative in-service date for the new SMS at Shaft #3 is November 1, 2021, as of May 2020.

Note that the cost estimate submitted in C55 in May 2020 is based on the feasibility-level, Class 5 estimate prepared by the Capital Development Team in 2019, plus a 40% contingency, and this total cost excludes any aid-to-construct (to be confirmed after the contract is signed). The budget-level estimate is still outstanding, and the costs and aid-to-construct amount contained in C55 will be revised and re-submitted after the exact terms of the contract are known.

Resources: To be confirmed - the construction work will be performed by company crew or an Alliance Partner.

Solution Impact: Increased revenue for EGI, as well as expanded company presence and increased market share.

Project Timing and Execution Risk: The tentative in-service date is set for November 1, 2021. Based on information from the Sales Account Manager, there is a high likelihood that Kirkland Lake Gold will wish to proceed with the proposed work; however, there is the possibility that the customer does not agree to the contract. Resources need to be confirmed. Potential execution risks include limited resources due to competing project priorities in 2021, or any timing or execution delays that may be imposed by the customer (Kirkland Lake Gold).

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Growth - System Reinforcement
Investment Stage	Short Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_45 - Timmins
	Asset Program (EGI)	GTH - System Reinforcement
	Asset Class (EGI)	Growth
2. Compliance	Compliance Investment	Yes
	Compliance Justification & Code	EBO 188 Compliance
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

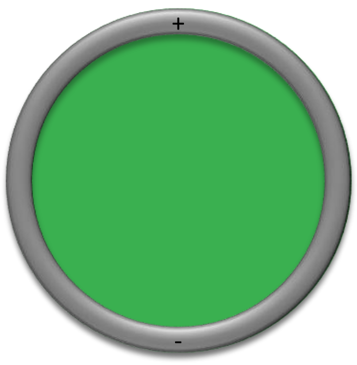
Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Construct New SMS at Shaft #3, including NPS 4 Service	Recommended	$ (2,111,667)	0.00	$ 2,280,600	1/1/2021

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 2,280,600	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

ENBRIDGE **Investment Summary Report**	Investment Code **103275**	Report Start Year **2021**	Number of Years **5**
	Investment Name TIMM: Macassa Mine New Shaft #3 SMS		

Alternative Value - Recommended



	Value Function Measure	Value	Value in Percentage
■	Financial Risk	0	0%
■	Employee And Contractor Safety Risk	0	0%
■	Environmental Risk And Remediation	0	0%
■	Public Safety Risk	0	0%
■	Reputational Risk	0	0%
■	Operational Risk	0	0%
■	Total Investment Cost (CA)	(2,112)	100%
	Total	**(2,112)**	**100%**

ENBRIDGE **Investment Summary Report**	Investment Code **49929**	Report Start Year **2021**	Number of Years **5**
	Investment Name WATE - Owen Sound Reinforcement Ph 4		

Investment Description

Issue/Concern: System Reinforcement
NPS 12 ST looping from Durham to Chatsworth of the Owen Sound transmission system for both EPCOR and general growth.

The Owen Sound area continues to grow as retirees move from the Greater Toronto Area. A current reinforcement is underway to supply increasing demands (including EPCOR) in the region - this project is the next phase in reinforcing this network to support forecasted growth. This project will install approximately 28 kilometres of NPS 16 pipe (replacing NPS 8 pipe) from Wellington Road, Harriston to the Durham gate station.

Assets: 28 kilometres of NPS 16 pipe from Wellington Road, Harriston to the Durham gate station

Related Programs: N/A

Recommended Alternative Description

Scope of Work: Station Replacement Program: Proactive replacement program that targets stations based on obsolescence, condition and age. This project will install approximately 28 kilometres of NPS 16 pipe (replacing NPS 8 pipe) from Wellington Road, Harriston to the Durham gate station.

Solution Impact: This reinforcement project will ensure the system has adequate flow capacity in anticipation of projected customer growth.

Resources: Company crews, contractor labour and third-party vendor suppliers

Project Timing and Execution Risks: Weather impacts, resource availability, procurement issues, etc.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Growth - System Reinforcement
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_07 - Waterloo
	Asset Program (EGI)	GTH - System Reinforcement
	Asset Class (EGI)	Growth
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (56,481,627)	0.00	$ 56,623,896	1/1/2020

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 1,920,625	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended

Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(56,482)	100%
Total	**(56,482)**	**100%**

ENBRIDGE Investment Summary Report	Investment Code 49773	Report Start Year 2021	Number of Years 5
	Investment Name WATE: Owen Sound Transmission System, Reinforcement (28.8km of NPS 16)		

Investment Description

Issue/concern: Reinforcement projects broadly involve the installation of new or modification of existing gas distribution assets to maintain minimum required system pressure, maintain capacity, and meet customer demand. These projects are primarily driven by customer growth and system reliability considerations. Failure to implement reinforcement projects in a timely manner could lead to a potential inability to support increasing demands of existing customers and the addition of future customers.

Assets: Owen Sound Transmission System - reinforcement of 28.8 kilometres of NPS 16 pipe.

Related Programs: N/A

Recommended Alternative Description

Scope of work: Lift and lay 28.8 kilometres of existing NPS 8 pipe with NPS 16 steel pipe. Cross country from approximately 9302 Wellington Road 6, Harriston to Durham Gate Station.

Resources: Company crews, contractor labour and third-party vendor suppliers

Solution Impact: This reinforcement project will ensure the system has adequate flow capacity in anticipation of projected customer growth. Approximately 1,300 customers are added annually in the region.

Project Timing and Execution Risks: Scheduled to be in service in November 1, 2025 or else customers could be lost from the system due to low pressure on peak day - the project will allow for a forecasted five years of growth. Risks: Weather impacts, resource availability, procurement issues, etc.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Growth - System Reinforcement
Investment Stage	Long Term Planning		

Investment Overview

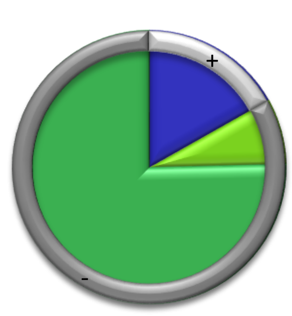
1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_07 - Waterloo
	Asset Program (EGI)	GTH - System Reinforcement
	Asset Class (EGI)	Growth
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (50,149,743)	0.12	$ 83,551,000	1/1/2023

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ -	$ -	$ 141,000	$ 4,580,000	$ 77,000,000
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Revenue Impact (CA)	12,763	17%
Financial Risk	0	0%
Public Safety Risk	0	0%
Budget Savings OPEX (CA)	(5,876)	8%
Total Investment Cost (CA)	(57,036)	75%
Total	**(50,150)**	**100%**

Distribution Pipe

ENBRIDGE Investment Summary Report	Investment Code **1791**	Report Start Year **2021**	Number of Years **5**
	Investment Name Augusta NPS 8		

Investment Description

Issue/Concern:
Annual Class Location surveys are required as per the Canadian Standards Association Z662 – Oil and Gas Pipeline Systems for pipelines greater than 30% SMYS. Any changes in class location need to be assessed to the current standard to determine if pipeline modifications are required. Urban development occurs in close proximity to EGI's pipelines which triggers annual class location changes; this work ensures EGI is compliant and fosters the safety of the public and the pipeline system.

Assets: Augusta 8 - 2400 metres of NPS 8, 2 roads Class 1 to 2.

Related Programs: N/A

Recommended Alternative Description

Scope of Work: Replace 2400 metres of NPS 8, 2 road crossings.

Solution Impact: The NPS 8 Augusta line will be designed and installed to address the class location change in this area; this work ensures EGI is compliant to CSA Z662 and fosters the safety of the public and the pipeline system.

Resources: Engineering Construction will manage the planning and execution of this project.

Project Timing and Execution Risks: Cost estimates continue to be refined as project design progresses and approaches construction. Depending on the location of the work, the project might require temporary land rights acquisition and special permitting ahead of execution, which could have an impact to the project schedule.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - DP - Main Replacement - Class Location Replacement Program
Investment Stage	Short Term Planning		

Investment Overview

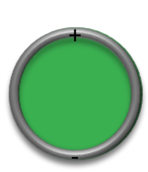
1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_22 - Kingston
	Asset Program (EGI)	DP - Main Replacement
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	Yes
	Compliance Justification & Code	Annual Class Location surveys are required as per the Canadian Standards Association Z662 – Oil and Gas Pipeline Systems for pipelines greater than 30 per cent SMYS. This work ensures EGI is compliant and fosters the safety of the public and the pipeline system.
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1: Replacement	Recommended	$ (5,555,556)	0.00	$ 6,000,000	1/1/2021

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 6,000,000	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(5,556)	100%
Total	**(5,556)**	**100%**

Investment Summary Report	Investment Code	Report Start Year	Number of Years
	48691	2021	5
	Investment Name		
	Bruce Lake Lateral		

Investment Description

Issue/Concern:

General Concerns: The capital expenditure included in this category covers a variety of planned maintenance projects. The projects covered under this expenditure include low pressure system replacements, distribution pipeline replacements due to historical leakage and integrity concerns, pipeline casing replacements, bridge and water crossing replacements and repairs etc. These projects are often identified through planned inspections and pipeline surveys and would then be assessed and planned based on risk and resource availability.

Project Specific: The Bruce Lake Lateral Maximum Operating Pressure (MOP) Upgrade project has been ongoing since 2017. This project is required to address capacity constraints on this system and ensure that contractual obligations can continue to be met. Work completed in 2017 was primarily focused on make piggable work for planned in-line inspection during the winter of 2017/2018. The line was inspected with ILI in 2018 and then again inspected in the winter of 2018/2019 with the addition of a flare stack to create more control over flow in the system. This second inspection was fully successful and provided the Integrity team with the required data to assess required repairs on the lateral prior to pressure testing. A total of 69 defects were identified requiring remediation – 29 of those defects were remediated in 2019.

Assets: Bruce Lake Lateral

Related Programs: N/A

Recommended Alternative Description

Scope of Work: In 2020 the work plan is focused on remediating the remaining 40 defects in order to be in a position to complete the remaining MOP upgrade activities in 2021.

In 2021, the work plan includes segmenting the 127-kilometres Bruce Lake lateral into a minimum of five segments for pressure testing, trucking in LNG to maintain system supply during the pressure tests, and completion of any required remediation as a result of pressure test results Work will also include a leak survey of the lateral post completion of the pressure test and completion of any remaining outstanding Engineering Assessment requirements in order to document and obtain approval from the TSSA for the final MOP Upgrade.

Solution Impact: Bruce Lake Lateral MOP Upgrade will be completed and approved by TSSA.

Resources: Engineering Construction will manage the planning and execution of this project.

Project Timing and Execution Risks: Cost estimates continue to be refined as project design progresses and approaches construction. Depending on the location of the work, the project might require temporary land rights acquisition and special permitting ahead of execution, which could have an impact to the project schedule.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - DP - Main Replacement - General Mains Replacement
Investment Stage	Executing		

Investment Overview

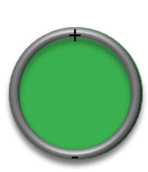
1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_54 - Head Office Support
	Asset Program (EGI)	DP - Main Replacement
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (13,550,989)	0.00	$ 13,921,359	1/1/2020

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 5,000,000	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(13,551)	100%
Total	**(13,551)**	**100%**

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
1790	2021	5

Investment Name

Coniston Lateral Replacement

Investment Description

Issue/Concern:
General Concerns: Annual Class Location surveys are required as per the Canadian Standards Association Z662 – Oil and Gas Pipeline Systems for pipelines greater than 30% SMYS. Any changes in class location need to be assessed to the current standard to determine if pipeline modifications are required. Urban development occurs in close proximity to EGI's pipelines which triggers annual class location changes; this work ensures EGI is compliant and fosters the safety of the public and the pipeline system.

Project Specific Concerns: Coniston Lateral Replacement - Replace 1100 metres of NPS 4, two roads Class 1 to 2.

Assets: Coniston Lateral

Related Programs: N/A

Recommended Alternative Description

Scope of Work: Replace 1100 metres of NPS 4 and two road crossings.

Solution Impact:The Coniston Lateral line will be designed and installed to address the class location change in this area; this work ensures EGI is compliant to CSA Z662 and fosters the safety of the public and the pipeline system.

Resources: Engineering Construction will manage the planning and execution of this project.

Project Timing and Execution Risks: Cost estimates continue to be refined as project design progresses and approaches construction. Depending on the location of the work, the project might require temporary land rights acquisition and special permitting ahead of execution, which could have an impact to the project schedule.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - DP - Main Replacement - Class Location Replacement Program
Investment Stage	Short Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_43 - Sudbury & S.S. Marie
	Asset Program (EGI)	DP - Main Replacement
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	Yes
	Compliance Justification & Code	Annual Class Location surveys are required as per the Canadian Standards Association Z662 – Oil and Gas Pipeline Systems for pipelines greater than 30 per cent SMYS. This work ensures EGI is compliant and fosters the safety of the public and the pipeline system.
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1: Replacement	Recommended	$ (2,777,778)	0.00	$ 3,000,000	1/1/2021

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 3,000,000	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended

Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(2,778)	100%
Total	**(2,778)**	**100%**

Investment Code	Report Start Year	Number of Years
49459	2021	5

ENBRIDGE

Investment Summary Report

Investment Name

HAMI - 20" Shorted Casing on Hwy 5 - Phase 1

Investment Description

Issue/Concern: This project includes the replacement of approximately 40 metres of 20" main which is shorted to the casing around it under Highway 5 in Flamborough. A non-conformance was issued for this work by the Corrosion department. This is one of two shorted casings close to each other on the outlets of Hamilton Gate 1 and 2. The west-most one is of higher importance due to condition as identified by corrosion technicians.

Assets: FID 555217110 (Highway 5 crossing of Gate 1 outlet)

Related Programs: 49460

Recommended Alternative Description

Scope of Work:
The Corrosion Program includes the required expenditure to replace aging or obsolete rectifiers or any other general corrosion capital, excluding anodes, in order to reduce the amount of down plant within the system. These installations and replacements are based on the internal Standard Operating Practice established to maintain the appropriate level of cathodic protection on steel pipeline assets or are driven by business cases to improve efficiencies in the corrosion program.
This project includes the replacement of approximately 40 metres of 1900kPa MOP 20" pipe within a casing under Highway 5. This pipe is near the outlet of Gate 1 and feeds the Hamilton high pressure loop which surrounds and feeds all of Hamilton.

Solution Impact: Once this is completed, the risk of loss of containment on this line will be eliminated. This line is an extremely important feed to all of Hamilton. Gate 1 is being rebuilt and it is important that to be able to use the station and line to their full capacity.

Resources: Engineering Construction will complete the work. It will require outside contractors for stopping and tapping.

Timing and Execution Risks: The project can only be completed in the summer months as Gate 2 and 3 will need to act as back-ups while this section of the line is shut down. Gas from Gate 3 is purchased from TCPL and nominations need to be considered for the time that it will be used more than normal. Temporary land may be required from nearby land owners to allow for room to work. The city of Hamilton will need to approve the work under their right of way (ROW). Cost estimates continue to be refined as project design progresses and approaches construction.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - DP - Corrosion - Corrosion
Investment Stage	Short Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_16 - Hamilton
	Asset Program (EGI)	DP - Corrosion
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
40m of 20" 1900kPa MOP pipe replacement	Recommended	$ (2,727,778)	0.00	$ 2,946,000	1/1/2021

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 2,946,000	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended

Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(2,728)	100%
Total	**(2,728)**	**100%**

Investment Code	Report Start Year	Number of Years
48252	**2021**	**5**

Investment Name

INTE: North Shore - Section A : Retrofit ECDA to ILI

ENBRIDGE

Investment Summary Report

Investment Description

Issue/Concern:

General: The Integrity Retrofit portion of the Integrity Management Program is to specifically capture retrofit work to make pipelines inline inspectable. The Integrity Management Program is a mandated regulatory requirement which has been designed to comply with all applicable codes and standards. The program consists of the regular assessment and maintenance of the integrity of pipeline systems at EGI to ensure their continued safety and reliability. Most of the expenditure included in this category is for pipelines that operate above 30% SMYS. It includes installation costs for permanent in-line inspection (ILI) tool launcher and receiver facilities, retrofits to existing lines to remove restrictive fittings or pipe configurations so they can be inspected with ILI tools, and remediation of pipeline segments with integrity issues that are identified through the inspections.

Project-specific concerns: External Corrosion Direct Assessment (ECDA) to ILI; no previous inline inspection. Associated 2021 O&M spend.

Assets: NPS 12 North Shore Lateral

Related Programs: N/A

Recommended Alternative Description

Scope of Work: Retrofit North Shore Lateral by installing in-line inspection (ILI) launcher and receiver facilities, removing non-piggable valve installations and other fittings installed on the pipeline. Pipeline will be segmented into multiple sections for ILI to keep run duration manageable.

Solution Impact: This retrofit project will allow the North Shore Lateral pipeline to be inspected using in-line inspection. Performing ILI will enhance the quantity and quality of pipeline condition data available for integrity management purposes including risk mitigation activities and fitness for service assessments.
In-line Inspection is part of EGI's Integrity Management Program, a regulatory requirement designed to comply with all applicable codes and standards.

Resources: Engineering Construction will manage the planning and execution of the retrofit project.

Timing and Execution Risks: This project is scheduled for design in 2020 and execution in 2021. Cost estimates continue to be refined as project design progresses and approaches construction. Depending on the location of the retrofits, the work might require temporary land rights acquisition and special permitting ahead of execution, which could have an impact to the project schedule.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - DP - Integrity - Integrity Retrofit
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_46 - North Bay & Orillia
	Asset Program (EGI)	DP - Integrity
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1: Retrofit	Recommended	$ (11,411,111)	0.00	$ 12,300,000	1/1/2020

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 12,000,000	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended

Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(11,411)	100%
Total	**(11,411)**	**100%**

Investment Code	Report Start Year	Number of Years
102211	2021	5

ENBRIDGE

Investment Summary Report

Investment Name

INTE: Norwich South: ECDA to ILI

Investment Description

Issue/Concern:

General: The Integrity Retrofit portion of the Integrity Management Program is to specifically capture retrofit work to make pipelines inline inspectable. The Integrity Management Program is a mandated regulatory requirement which has been designed to comply with all applicable codes and standards. The program consists of the regular assessment and maintenance of the integrity of pipeline systems at EGI to ensure their continued safety and reliability. Most of the expenditure included in this category is for pipelines that operate above 30% SMYS. It includes installation costs for permanent in-line inspection (ILI) tool launcher and receiver facilities, retrofits to existing lines to remove restrictive fittings or pipe configurations so they can be inspected with ILI tools, and remediation of pipeline segments with integrity issues that are identified through the inspections.

Assets: NPS 6 Norwich South Line

Related Programs: Integrity Management Program

Recommended Alternative Description

Scope of Work: Retrofit Norwich South Line by installing in-line inspection (ILI) launcher and receiver facilities, removing non-piggable valve installations and other fittings installed on the pipeline.

Solution Impact: This retrofit project will allow the Norwich South Line to be inspected using in-line inspection. Performing ILI will enhance the quantity and quality of pipeline condition data available for integrity management purposes including risk mitigation activities and fitness for service assessments.
In-line inspection is part of EGI's Integrity Management Program, a regulatory requirement designed to comply with all applicable codes and standards.

Resources: Engineering Construction will manage the planning and execution of the retrofit project.

Project Timing and Execution Risks: Cost estimates continue to be refined as project design progresses and approaches construction. Depending on the location of the retrofits, the work might require temporary land rights acquisition and special permitting ahead of execution, which could have an impact to the project schedule.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - DP - Integrity - Integrity Retrofit
Investment Stage	Short Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_06 - Brantford
	Asset Program (EGI)	DP - Integrity
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	Yes
	Compliance Justification & Code	The Integrity Management Program is a mandated regulatory requirement which has been designed to comply with all applicable codes and standards. The program consists of the regular assessment and maintenance of the integrity of Union's pipeline systems to ensure their continued safety and reliability. Most of the expenditure included in this category is for pipelines that operate above 30 per cent SMYS
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

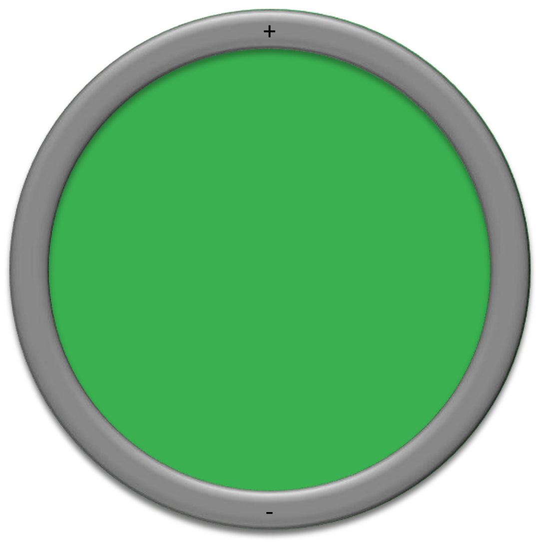
Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Retrofit	Recommended	$ (2,546,296)	0.00	$ 2,750,000	1/1/2021

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 2,750,000	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Investment Summary Report	Investment Code	Report Start Year	Number of Years
	102211	**2021**	**5**
	Investment Name		
	INTE: Norwich South: ECDA to ILI		

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Financial Risk	0	0%
Employee And Contractor Safety Risk	0	0%
Environmental Risk And Remediation	0	0%
Public Safety Risk	0	0%
Reputational Risk	0	0%
Cost Avoidance CAPEX (CA)	0	0%
Cost Avoidance OPEX (CA)	0	0%
Budget Savings CAPEX (CA)	0	0%
Budget Savings OPEX (CA)	0	0%
Revenue Impact (CA)	0	0%
Operational Risk	0	0%
Total Investment Cost (CA)	(2,546)	100%
Total	**(2,546)**	**100%**

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
48248	2021	5

Investment Name

INTE: Owen Sound Section 5: Replace Road Crossing for 2021 ILI

Investment Description

Issue/Concern:
General: The Integrity Management Program is a mandated regulatory requirement which has been designed to comply with all applicable codes and standards. The program consists of the regular assessment and maintenance of the integrity of EGI's pipeline systems to ensure their continued safety and reliability. Most of the expenditure included in this category is for pipelines that operate above 30 per cent SMYS. It includes installation costs for permanent in-line inspection (ILI) tool launcher and receiver facilities, retrofits to existing lines to remove restrictive fittings or pipe configurations so they can be inspected with ILI tools, and replacement of pipeline segments with integrity issues identified through the inspections.

Project Specific: Enhance piggability of Owen Sound line prior to next ILI in 2021. Associated 2021 O&M spend. Previous ILIs have encountered lodged tools at this location resulting in speed excursions and missing and degraded data.

Assets: Owen Sound line

Related Programs: N/A

Recommended Alternative Description

Project Specific: Enhance piggability prior to next ILI in 2021. Associated 2021 O&M spend. Previous ILIs have encountered lodged tools resulting in speed excursions, missing and degraded data.

Resources: Engineering Construction group to provide project management support from design and planning phase to project execution.

Solution Impact: Replacing this section of pipe will eliminate speed excursions and result in a more complete and accurate ILI data set for evaluation as part of the TIMP program.

Project Timing and Execution Risks: Project is planned for early 2021. Proposal is based on Class 5 level cost estimates.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - DP - Integrity - Integrity Retrofit
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_07 - Waterloo
	Asset Program (EGI)	DP - Integrity
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1: Retrofit	Recommended	$ (4,000,366)	0.00	$ 4,200,366	1/1/2020

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 2,700,000	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended

Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(4,000)	100%
Total	**(4,000)**	**100%**

Investment Summary Report	Investment Code	Report Start Year	Number of Years
	102128	**2021**	**5**
	Investment Name: Kirkland Lake Lateral Replacement		

Investment Description

Issue/Concern:
The Kirkland Lake Lateral is 12 km of NPS 4 steel pipe of late 1950s vintage (1957/1958) operating at an MOP of 6895KPa / 1000psig (>30%SMYS) and is considered a transmission main under the Transmission Integrity Management Program (TIMP):
- Main runs through mostly bedrock with blasted main bed and rocky backfill.
- Depth of Cover (DoC) and backfill washout is a big concern- 2019 ECDA included a DoC survey and found over 1.3km of pipe with less than 0.6m of cover.
- One inoperable valve at Swastika.
- The main has 1 river crossing.
- Approximately 4 km of the 12 km of pipe was replaced for class location mitigation work.
- Lateral supplies Kirkland Lake and some mining customers and is looped with another NPS 8 main (Kirkland Lake Loop)
- Utilization for these two mains is nearing full capacity, especially when the addition of three new mines takes place:
    - When demand increases (i.e. addition of these three mines) this would eliminate the ability to use the NPS 8 system as a back feed / bypass to allow repairs on the NPS 4 mains, should additional leaks occur.
    - Repairs on the NPS 4 would then require local isolation via bypass, dramatically increasing leak repair costs and repair times.
- Since this is a transmission line operating >30%SMYS, any leaks must be repaired via cut-out replacements (no sleeves).
- This main was inspected by ECDA in 2007. The report gave an estimated 12-year life from that point in time and found 11 immediate dig locations.

- A leak was found in September 2019 (1st leak in at least 12 years) and was repaired via cut-out / replacement using the NPS 8 loop to isolate the NPS 4 as capacity demands allowed for this process.
  Repair cost was approximately $375K.
- ECDA inspection was performed in late fall of 2019:
    - 13 immediate digs in 12 locations were identified and require mitigation within 18 months (June 2021).
    - These digs are O&M expenses, if cut-out repair is required, this would be Capital (replacement of >1m of pipe)
    - An additional 40 indications were classified as "scheduled for investigation" and require investigation digs within 48 months (2023).
    - TIMP estimates a cost of approximately $100K per dig.
    - TIMP estimates that in total, approximately $6M in digs and repairs is required to mitigate these 53 indications.
- TIMP has imposed a pressure reduction to the main of 850 psig as a temporary mitigation.

Justification:
The NPV analysis for replace versus repair shows a strong recommendation towards replacing the main as the least costly option.

Assets: Kirkland Lake Lateral

Related Programs: TIMP Inspection Program

Recommended Alternative Description

Scope of Work: Due to the condition of the existing NPS 4 Kirkland Lake Lateral, a cost estimate has been requested for the replacement of the line. This is a result of the latest ECDA report on the pipeline. Portions of the line have recently been replaced in 2018 and 2019 as part of the Class Location program. The remaining sections are proposed for replacement (8.5 km total of NPS 4). This option is a size for size replacement.

Solution Impact:
Replacement with new pipe will remove the over 300 corrosion indications being found by ECDA and reduce the likelihood for corrosion leaks as well as damage, as the new main will be set to the correct depth of cover.

Resources:
2022 OTC - resources TBD

Project Timing & Execution Risk: A 2022 in-service date considering this option will most likely require OEB approval through a Leave To Construct (LTC) application.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - DP - Main Replacement - Vintage Steel Mains Replacement Program
Investment Stage	Short Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_45 - Timmins
	Asset Program (EGI)	DP - Main Replacement
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	Yes
	Compliance Justification & Code	2019 ECDA identified 13 Immediate Dig / Repair features that need to be mitigated no later than 2021, with an additional 40 features requiring scheduled mitigation by 2023. There are a further 300 indications being monitored. TIMP is suggesting that replacement versus repair be a preferred option. If the pipe is replaced then TIMP will remain in compliance. Otherwise repairs will be required for the 13 immediate and 40 scheduled digs through O&M.
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

![ENBRIDGE]

Investment Summary Report

Investment Code	Report Start Year	Number of Years
102128	2021	5

Investment Name

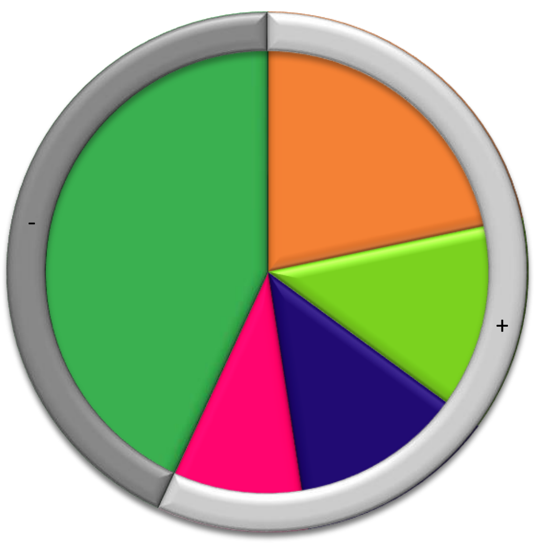
Kirkland Lake Lateral Replacement

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
NPS 4 Size for Size Replacement	Recommended	$ 4,614,115	1.32	$ 16,800,000	1/1/2021

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 600,000	$ 16,200,000	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Cost Avoidance OPEX (CA)	7,263	22%
Budget Savings OPEX (CA)	4,490	13%
Cost Avoidance CAPEX (CA)	4,180	12%
Budget Savings CAPEX (CA)	3,126	9%
Financial Risk	0	0%
Employee And Contractor Safety Risk	0	0%
Environmental Risk And Remediation	0	0%
Public Safety Risk	0	0%
Reputational Risk	0	0%
Revenue Impact (CA)	0	0%
Operational Risk	0	0%
Total Investment Cost (CA)	(14,444)	43%
Total	**4,614**	**100%**

ENBRIDGE	Investment Code	Report Start Year	Number of Years
Investment Summary Report	49607	2021	5
	Investment Name: LOND-London Lines Replacement		

Investment Description

Issue/Concern:
The London Lines is a pair of high pressure distribution pipeline that connects Dawn to the City of London, and the multiple municipalities in between and spans approximately 80.9 km. The London Lines consists of two high pressure (HP) pipelines running in parallel and is considered a major feed supplying gas to the small communities between Dawn and London. The line located further north is known as the London South Line and is comprised mainly of NPS 10 steel pipeline coated in Barrett Enamel and installed in 1935. The line located further south is known as the London Dominion Line and is comprised mainly of NPS 8 steel pipeline coated in Durnite and installed in 1936, which was subsequently replaced in 1952. The materials used were reclaimed and refurbished steel pipe from the Windsor district with an average vintage of 1920 - 1930.

There are a number of business benefits to replacing the London Lines pipelines as soon as possible::
- Integrity– associated risks from numerous outstanding leaks and future leak potential eliminated through replacement:
  - Pipeline is constructed with unrestrained Dresser coupling fittings.
  - Aerial crossings at ditches which in some instances are bare and/or have unrestrained Dresser couplings.
  - Inoperable valves including valves installed at grade/in the ground
  - Current system operates below MOP to reduce number of leaks.
  - Both pipelines installed in the 1950s - one line constructed using reclaimed pipe from Windsor of 1920s vintage.
  - Depth of cover issues in multiple sections.
  - Non-standard supports at deep ditches to allow access for leak survey.
  - Increased difficultly of repairs including finding pipe suitable for welding.
- O&M resources - a reduction in the amount of O&M resources needed to address, monitor, and fix new and outstanding leaks is substantial. Estimated cost of a new repair is $15-60k.
- System flexibility – the connection of Strathroy to the Dawn to Parkway system in two locations will provide resiliency to the network.

Assets:
London Lines consists of two HP pipelines running in parallel (London South Line and London Dominion Line).

Related Programs: N/A

Recommended Alternative Description

Scope of Work:
This project will install 83.5 kilometres of NPS 6 and NPS 4 steel pipe with a MOP of 3450 kpa (500 psi) from Dawn Compressor Station to Komoka Transmission Station, replacing the two pipelines known collectively as the London Lines. There will also be secondary new pipeline installed to connect the new NPS 6/4 pipeline to the town of Strathroy. The pipeline provides service, directly and indirectly, to approximately 8,500 customers.

Resources:
2021 - OTC and would be bid on by external contractors

Solution Impact:
Main replacement project identified by Operations - Pipelines as high-priority. Replacement is required due to age, pipeline condition and risk assessment results. This confirmed the timing for execution of this replacement project for 2021.

Timing and Execution Risks:
Risks: Moratoriums, third party developments, COVID-19 impacts, permitting and required easements.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - DP - Main Replacement - General Mains Replacement
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_03 - Sarnia
	Asset Program (EGI)	DP - Main Replacement
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

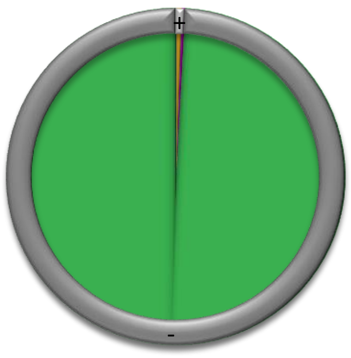
Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (101,814,948)	0.00	$ 110,251,177	1/1/2020

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 97,899,180	$ 8,302,453	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ 22,376,991	$ -	$ -	$ -

	Investment Code	Report Start Year	Number of Years
ENBRIDGE Investment Summary Report	**49607**	**2021**	**5**
	Investment Name: LOND-London Lines Replacement		

Alternative Value - Recommended



	Value Function Measure	Value	Value in Percentage
	Operational Risk	520	1%
	Financial Risk	357	0%
	Reputational Risk	0	0%
	Employee And Contractor Safety Risk	0	0%
	Environmental Risk And Remediation	0	0%
	Public Safety Risk	0	0%
	Total Investment Cost (CA)	(101,815)	99%
	Total	**(100,937)**	**100%**

ENBRIDGE Investment Summary Report	Investment Code	Report Start Year	Number of Years
	100295	2021	5
	Investment Name: NPS 8 Port Stanley Replacement		

Investment Description

Issue/Concern/Opportunity:
The NPS 8 Port Stanley line is approximately 20 kilometres of NPS 8 built in 1959, with unknown grade and wall thickness, bare and protected, Dresser construction (some gas welded – such welds are usually susceptible to lack of fusion imperfections). There has been a history of a significant number of leaks due to corrosion on this single-feed system that provides natural gas to Port Stanley and St. Thomas, with about 13,000 customers including the St. Thomas hospital, a psychiatric hospital in St. Thomas and a retirement home in Port Stanley.

External corrosion has created difficulties with repairs due to the inability to weld. In one repair case, it took Operations three weeks to locate a suitable weld location for a repair. Repairs often require the use of split sleeves ($8K/ea). Depth of cover is a significant risk factor, with two exposed pipe sections being reported over creek crossings in December 2019. There are significant accessibility issues with locations of the pipe, making it difficult for emergency response and condition surveys. Some sections of pipe are heavily over-grown while other locations can be over 500 metres from the nearest road. There are three below-grade stations that are considered confined spaces and which often flood, and must be evacuated before inspections and maintenance can occur. Gas supply from Lake Erie (New Dundee Comp) was known to have high moisture content and may contribute to internal corrosion.

No isolation is built into the single feed system, so if supply needs to be shut down, all downstream customers would be affected. 6.8 kilometres of main were replaced in 2000 due to corrosion and exposed pipe. 230 metres were replaced in 2003 due to a Class B leak under a river crossing. Three casings on the system are known to be shorted. An attempted pressure increase in 1970 resulted in numerous leaks from compression couplings and pipe, therefore the pipe cannot be pressure elevated.

Assets: The Port Stanley line is approximately 20 kilometres of NPS 8 built in 1959.

Related Programs: N/A

Recommended Alternative Description

Scope of Work: Straight replacement of existing NPS8 utilizing right of way (ROW) only. This would involve the installation of 19.4 kilometres of NPS 8 steel gas main through ROW along existing roadway.

Solution Impact:
This option would eliminate access issues faced today with the gas main being installed through agricultural lands within easements.

Resources:
2024 - OTC and would be bid on by external contractors

Timing and Execution Risks:
Moratoriums, third party developments, COVID-19 impacts, permitting and required easements.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - DP - Main Replacement - Vintage Steel Mains Replacement Program
Investment Stage	Long Term Planning		

Investment Overview

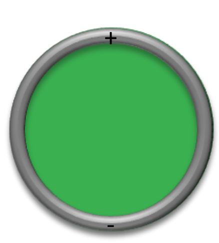
1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_04 - London
	Asset Program (EGI)	DP - Main Replacement
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Port Stanley Replacement Option 1D	Recommended	$ (15,200,653)	0.00	$ 20,641,920	1/1/2023

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ -	$ -	$ 480,000	$ 20,161,920	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



	Value Function Measure	Value	Value in Percentage
	Financial Risk	0	0%
	Public Safety Risk	0	0%
	Total Investment Cost (CA)	(15,201)	100%
	Total	**(15,201)**	**100%**

ENBRIDGE Investment Summary Report	Investment Code: 2143	Report Start Year: 2021	Number of Years: 5
	Investment Name: Sudbury Section 1 - Yellek		

Investment Description

Issue/Concern:

General Concerns: Annual Class Location surveys are required as per the Canadian Standards Association Z662 – Oil and Gas Pipeline Systems for pipelines greater than 30% SMYS. Any changes in class location need to be assessed to the current standard to determine if pipeline modifications are required. Urban development occurs in close proximity to EGI's pipelines which triggers annual class location changes; this work ensures EGI is compliant and fosters the safety of the public and the pipeline system.

Project Specific Concerns: Sudbury Section 1 - Yellek - 2500m of NPS 10. 3 road crossings. Class 1 to 2.

Assets: Sudbury Section 1 - Yellek - 2500 metres of NPS 10 pipe.

Related Programs: N/A

Recommended Alternative Description

Scope of Work: Replace 2500 metres of NPS 10, 3 road crossings

Solution Impact: The Sudbury Section 1 line will be designed and installed to address the class location change in this area; this work ensures EGI is compliant to CSA Z662 and fosters the safety of the public and the pipeline system.

Resources: Engineering Construction will manage the planning and execution of this project.

Project Timing and Execution Risks: Cost estimates continue to be refined as project design progresses and approaches construction. Depending on the location of the work, the project might require temporary land rights acquisition and special permitting ahead of execution, which could have an impact to the project schedule.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - DP - Main Replacement - Class Location Replacement Program
Investment Stage	Short Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_43 - Sudbury & S.S. Marie
	Asset Program (EGI)	DP - Main Replacement
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	Yes
	Compliance Justification & Code	Annual Class Location surveys are required as per the Canadian Standards Association Z662 – Oil and Gas Pipeline Systems for pipelines greater than 30 per cent SMYS. This work ensures EGI is compliant and fosters the safety of the public and the pipeline system.
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1: Replacement	Recommended	$ (2,222,222)	0.00	$ 2,400,000	1/1/2021

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 2,400,000	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended

Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(2,222)	100%
Total	**(2,222)**	**100%**

ENBRIDGE Investment Summary Report	Investment Code	Report Start Year	Number of Years
	2142	2021	5
	Investment Name: Sudbury Section 1 Sturgeon River North Side		

Investment Description

Issue/Concern - Replace 236 metres of NPS 10 steel transmission piping from the intersection of Delorme Street and Smilie Road to approximately 275 metres south of Smiley Road MLV. Chainage 43236 – 43472. Class 1 to Class 2 change. General concerns: Annual Class Location surveys are required as per the Canadian Standards Association Z662 – Oil and Gas Pipeline Systems for pipelines greater than 30% SMYS. Any changes in class location need to be assessed to the current standard to determine if pipeline modifications are required. Urban development occurs in close proximity to EGI's pipelines, which triggers annual class location changes; this work ensures EGI is compliant and fosters the safety of the public and the pipeline system.

Assets: Sudbury Section 1 Sturgeon River

Related Programs: N/A

Recommended Alternative Description

Scope of Work: Replace 800 metres of NPS 10, two road crossings and a river crossing.

Solution Impact: The Sudbury Section 1 line will be designed and installed to address the class location change in this area; this work ensures EGI is compliant to CSA Z662 and fosters the safety of the public and the pipeline system.

Resources: Engineering Construction will manage the planning and execution of this project.

Project Timing and Execution Risks: Cost estimates continue to be refined as project design progresses and approaches construction. Depending on the location of the work, the project might require temporary land rights acquisition and special permitting ahead of execution, which could have an impact to the project schedule.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - DP - Main Replacement - Class Location Replacement Program
Investment Stage	Short Term Planning		

Investment Overview

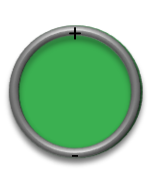
1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_43 - Sudbury & S.S. Marie
	Asset Program (EGI)	DP - Main Replacement
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	Yes
	Compliance Justification & Code	Annual Class Location surveys are required as per the Canadian Standards Association Z662 – Oil and Gas Pipeline Systems for pipelines greater than 30 per cent SMYS. This work ensures EGI is compliant and fosters the safety of the public and the pipeline system.
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1: Replacement	Recommended	$ (2,129,630)	0.00	$ 2,300,000	1/1/2021

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 2,300,000	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(2,130)	100%
Total	**(2,130)**	**100%**

ENBRIDGE Investment Summary Report	Investment Code	Report Start Year	Number of Years
	48670	2021	5
	Investment Name		
	Windsor Line Replacement		

Investment Description

Issue/Concern:
A significant portion of the Windsor Line was installed in the 1930s, 1940s, and 1950s. Although this pipeline one of the oldest operating assets within the Union rate zones, it is not age alone that is driving the need for replacement. There are many other factors related to its condition that are more relevant than its age in considering the need for replacement:
- History of leakage with significant costs to repair
- All joints prior to 2000s were made with unrestrained mechanical couplings; portions of the older vintage pipe are not weldable.
- Some sections of the line cannot be isolated because of inoperable mainline valves.
- The line has sections that have poor depth of cover with less than 0.6 meters.
- Sections of this pipeline are not located in easement.

Based on these concerns and the significant effort and resources spent already repairing leaks, the Windsor Line has been deemed an operational risk. To manage this risk, the line has been identified for replacement of those sections with the highest risk as identified above.

Assets:
Replacement of approximately 64 kilometres of the existing Windsor Line natural gas pipeline, (primarily a 10-inch diameter pipeline with some short sections of 8-inch pipeline), with a new 6-inch diameter pipeline.

Related Programs: N/A

Recommended Alternative Description

Scope of Work: The proposed project will replace 61.4 kilometres of the existing Windsor 10” pipeline, and construct a new ~65-kilometres, 6” distribution line operating at a higher operating pressure, between Windsor and Port Alma, which is expected to be placed into service on November 1, 2020.

Resources:
OTC 2020 with external contractors

Solution Impact:
Main replacement project identified by Operations - Pipelines as high-priority. Replacement is required due to age, pipeline condition and risk assessment results.

Timing and Execution Risks:This confirmed the timing for execution of this replacement project for 2020. Risks: Moratoriums, third party developments, COVID-19 impacts, permitting and required easements.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - DP - Main Replacement - General Mains Replacement
Investment Stage	Executing		

Investment Overview

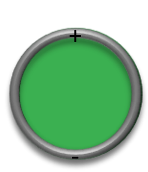
1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_01 - Windsor
	Asset Program (EGI)	DP - Main Replacement
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (85,666,753)	0.00	$ 86,199,958	1/1/2020

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 7,198,274	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ 1,920,518	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(85,667)	100%
Total	**(85,667)**	**100%**

Distribution Stations

Investment Summary Report	Investment Code	Report Start Year	Number of Years
	101078	2021	5
	Investment Name: HALT- Milton Gate, Milton, Boiler Replacement		

Investment Description

Issue/Concern/Opportunity:
Natural gas heating equipment is used in many stations across EGI to help mitigate failure of equipment due to the freezing of liquids in the gas stream as well as moisture that surrounds buried piping. Over the companies many years of operation, a variety of heating systems have been used resulting in many variations of equipment age, and the introduction of equipment obsolescence. This project includes ongoing maintenance to replace equipment that has reached end-of-life or has been deemed obsolete. This work will maintain system reliability, ensure operating costs for heating systems are minimized and reduce the potential for glycol spills. The heating system was identified during the Indirect Fire Heater assessment in 2019, and the recommendation was to replace the boilers. In addition, there are corrosion concerns of the station piping due to deteriorating/open piping insulation and there are heaving issues at this site.

Assets: Station #19X-301

Related Investments: N/A

Recommended Alternative Description

Scope of Work: Replace the aging heating system to improve efficiency and reduce operating costs of to mitigate the risk of equipment failures that could result in loss of customers and/or loss of glycol containment.

Solution Impact: Replacing the heating system at the station will mitigate safety risks to employees, contractors, and the general public.

Resources:Company crews, contractor labour and third party vendor suppliers

Project Timing and Execution Risk: Planning and execution in Year 1.
Execution Risk - Weather impacts, resource availability, procurement, etc.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Distribution Stations - Gate, Feeder & A Stations
Investment Stage	Long Term Planning		

Investment Overview

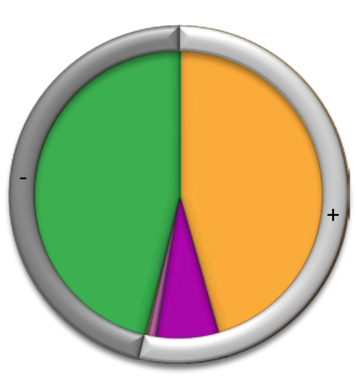
1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_17 - Halton
	Asset Program (EGI)	DS - Gate, Feeder & A Stations
	Asset Class (EGI)	Distribution Stations
2. Compliance	Compliance Investment	
	Compliance Justification & Code	
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
replace Boilers	Recommended	$ (2,777,778)	0.00	$ 3,000,000	1/1/2021

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 3,000,000	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Environmental Risk And Remediation	2,746	46%
Financial Risk	420	7%
Reputational Risk	52	1%
Operational Risk	21	0%
Employee And Contractor Safety Risk	0	0%
Public Safety Risk	0	0%
Total Investment Cost (CA)	(2,778)	46%
Total	**462**	**100%**

ENBRIDGE Investment Summary Report	Investment Code **49058**	Report Start Year **2021**	Number of Years **5**
	Investment Name WATE: Waterloo Gate Stn Rebuild, Waterloo, Growth		

Investment Description

Issue/Concern:
The Waterloo Gate station configuration and condition of existing equipment is not functioning in a reliable manner.

- Pipe, Valves and Others: The filter condition requires replacement, the over pressure protection will be modified to include a monitor-operator setup, and the outlet piping requires upsizing.

- Heating System: The heating system requires an analysis and potential upsizing to meet the current station needs.

- Telemetry/Electrical: Reworking of electrical and additional heat trace to be investigated.

- Compliance/Civil: Access to the site can be improved.

Asset: Station # 19S-601

Related Program(s): N/A

Recommended Alternative Description

Scope of Work:
Build a brand new station behind existing station (ie. farther away from Fischer-Hallman).
Build the 9.S-147 new station (July-August 2021) with:
- Additional regulator run (3rd)
- All three regulator runs to be a monitor operator setup.
- Outlet piping increase from NPS 8 to NPS 10
- Inlet piping to stay current pipe size

To complete this, the following needs to occur:
- Install new 12” isolation valve on the HP inlet (potential that existing does not fit stopple or stopple train).
- Station needs to be on bypass during build of new station.
- Replace the existing filter.
- Potentially replace the heat exchanger (2012) but might be too small (evaluate during design).
- Abandon the 1900kPa cut leaving this station.
- Move the RTU and cabinet to the new station location.
- Move the boiler building with boilers to the new location.
- Move heat exchanger to new site – include concrete pad/support.
- Build new driveway along the side of the property.
- Trees along fence line of the property.

Solution Impact: Rebuilding the station will mitigate safety risks to employees, contractors, and the general public.

Resources: Engineering Construction will complete the construction. They have provided a feasibility level costing. In addition, the Integrity team has been asked to review whether the provision for the launcher and receiver should be built to a permanent launcher and receiver.

Project Timing and Execution Risks: N/A

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Distribution Stations - Station Rebuilds & B and C Stations
Investment Stage	Short Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_07 - Waterloo
	Asset Program (EGI)	DS - Station Rebuilds & B and C Stations
	Asset Class (EGI)	Distribution Stations
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Full Station Rebuild	Recommended	$ (1,862,594)	0.00	$ 2,011,601	1/1/2021

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 2,011,601	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Investment Summary Report	Investment Code	Report Start Year	Number of Years
	49058	2021	5
	Investment Name		
	WATE: Waterloo Gate Stn Rebuild, Waterloo, Growth		

Alternative Value - Recommended

Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(1,863)	100%
Total	**(1,863)**	**100%**

Investment Summary Report

Investment Code	Report Start Year	Number of Years
48318	**2021**	**5**

Investment Name

WIND-03D-301 Leamington North Gate

Investment Description

Issue/Concern: The Gate and Feeder Station Replacement Program manages the proactive replacement of component groups with the highest probability of failure, non-compliant assets, and the realization of opportunities for multiple component group replacements per station location as required.

The Leamington North Gate station has obsolete heating equipment and there are two boilers (circa 1985) that are problematic and have experienced glycol containment issues. The boiler controls have malfunctioned several times over the last to years.

The station piping presents ergonomic concerns as some sections are at ankle height.

Justification: Rebuild part of the station at the existing site; build a new station at a new location (essentially breaking the station into two new stations).

Assets: 03D-301 Leamington North Gate

Related Programs: N/A

Recommended Alternative Description

Scope of Work: 03D-301 Leamington North Gate station will be rebuilt into two stations. One will be built at a new location, and the second will be rebuilt on the existing site. The existing site has several environmental concerns that will be addressed through the execution of this project. The break up of this station is necessary to provide adequate growth to the system; the station cannot be expanded upon due to location (residential neighbourhood) and property size. This is Phase 1 of the project which entails the removal of 420 kPa pipe cut from the existing station and building a new 420 kPa station at Mersea Road 3 and Morse Road. 1 kilometre of 12" 420 kPa pipe will also be installed to tie this new station into the existing 420 kPa network.

Resources: Alliance partners, company resources, and third-party vendor suppliers

Solution Impact: Relocating the station location will mitigate safety risks to employees, contractors, and the general public.

Project Timing and Execution Risk: Planning and execution in Year 1 (Planning Oct 2020 - March 2021; Construction June to August 2021) / Execution Risk - Weather impacts, resource availability, procurement issues, etc.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Distribution Stations - Gate, Feeder & A Stations
Investment Stage	Short Term Planning		

Investment Overview

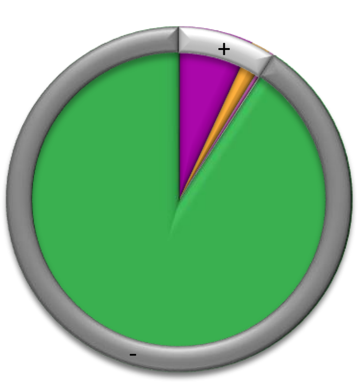
1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_01 - Windsor
	Asset Program (EGI)	DS - Gate, Feeder & A Stations
	Asset Class (EGI)	Distribution Stations
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (5,082,997)	0.00	$ 5,489,637	1/1/2021

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 5,489,637	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Financial Risk	386	7%
Environmental Risk And Remediation	102	2%
Reputational Risk	23	0%
Employee And Contractor Safety Risk	4	0%
Operational Risk	2	0%
Public Safety Risk	0	0%
Total Investment Cost (CA)	(5,083)	91%
Total	**(4,566)**	**100%**

Compression Stations

ENBRIDGE Investment Summary Report	Investment Code	Report Start Year	Number of Years
	48715	**2021**	**5**
	Investment Name: Dawn Plant-C Compression Lifecycle		

Investment Description

Issue/Concern:
Dawn C Plant is one of the nine centrifugal compressors located at the Dawn Compressor Station. It is primarily used to lift from lower storage pressure levels, experienced later in the operations season, to intermediate pressure levels. The intermediate pressure level is typically elevated further in pressure by another compressor to reach the desired Dawn outlet pressure. Dawn Plant C and Plant D have a suction pressure rating of 195 psig, the lowest rating of the compressor fleet at Dawn. Considering the other compressors at Dawn have a 225 psig minimum inlet rating, Dawn Plants C and D become very critical when pool storage levels fall below 225 psig, as they typically do late in the operational season. Overall, compression can pose a very large consequence of failure as compressors are integral assets required to achieve the Dawn to Parkway Transmission System deliverability requirements throughout the year. The consequence of compressor failure is dominated by gas cost impacts to customers. Transmission System consequences associated with failure of a single compressor are heavily influenced by the time of year, weather severity and time to mitigate the failure. Siemens, the original equipment manufacturer (OEM) of the Dawn C compressor, has indicated that 40 years is the typical timeframe for supporting the supply of engine parts required to recover from a critical engine failure or to complete recommended overhauls. Dawn Plant C was installed in 1984, which indicates that the RB211- 24A engine in Plant C is reaching end-of-life.

Justification:
By continuing to comply with OEM-recommended Preventive Maintenance (PM) schedules and overhauls, compressor reliability risk is controlled to moderate levels but risk increases gradually over the 25,000-hour recommended interval between overhauls. Availability of parts is essential to repair internal engine failures and complete overhauls. Notably, the RB211-24A in Plant C has non-standard dimensions and cannot be retrofitted with more modern editions of the RB211 without significant plant retrofits. Similar to the 40-year old Dawn Plant B, which was replaced and retired in 2017 due to the risks associated with discontinued OEM support of critical engine parts, it is expected that Dawn Plant C will be exposed to a similar level of risk at the age of 40.

Assets: Dawn Plant C

Related Programs: N/A

Recommended Alternative Description

Scope of Work:
Removal and abandonment of the plant, associated piping and electrical, and remediation of land back to level grade. A new compression facility and its associated infrastructure will be developed and installed at the Dawn Compressor Station.

Work includes full project gating cycle due to scale and complexity including: stakeholder consultations, planning, detailed design, permit applications, environmental assessment. procurement, retaining a construction contractor, isolate system, demolition of structures/equipment to be replaced, erect buildings if required, prefabricating piping, hydrotesting, install new piping and auxiliary systems, NDE as required, coating, inspection, train staff, energize system, remediating site, and records updates.

Resources:
Consultant resources for design
Contractor resources for abandonment, construction and commissioning
Regulatory approval

Solution Impact:
This project will ensure the safe removal of infrastructure and the replacement of 32,000 hp of obsolete compression to support the storage to transmission requirements at Dawn.

Project Timing and Execution Risk:
Regulatory approval and planning - two years, abandonment and remediation 18 months.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Compression Stations - Replacements
Investment Stage	Long Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_53 - Union South Storage
	Asset Program (EGI)	CS - Replacements
	Asset Class (EGI)	Compression Stations
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

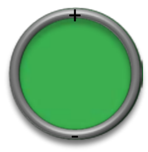
Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1 - Direct Replacement	Recommended	$ (102,105,529)	0.00	$ 130,956,000	1/1/2022

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ -	$ 16,212,000	$ 69,636,000	$ 40,908,000	$ 4,200,000
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Investment Summary Report	Investment Code	Report Start Year	Number of Years
	48715	2021	5
	Investment Name		
	Dawn Plant-C Compression Lifecycle		

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(102,106)	100%
Total	**(102,106)**	**100%**

Investment Summary Report	Investment Code	Report Start Year	Number of Years
	48732	2021	5
	Investment Name: Waubuno Compression Lifecycle		

Investment Description

Issue/Concern/Opportunity: The Waubuno compressor elevates available pipeline pressure to the Waubuno Pool MOP. Compression increases the working inventory value of the pool by approximately $2.2 million (at $0.75 per GJ) based on top of what the pipeline alone can achieve. The compressor is operated approximately 45 days per year in late summer to early fall to top off the pool. The consequence of compressor failure is dominated by customer impact. Risk associated with failure of the Waubuno compressor is heavily influenced by the level of the pool at which the failure occurs and time to mitigate the failure.

The Joy Compressor (manufactured in 1985) was a used compressor package and installed at Waubuno in 1988. The Joy Compressor Company changed ownership approximately 20 years ago whereupon original equipment manufacturer (OEM) support for the compressor was discontinued. Although normal wear components are still available in the marketplace, replacement major compressor items such as cylinders, crankshafts, and rods, etc., required to support a critical failure are no longer available. In the event of a critical failure, sourcing used parts (which are rare) or aftermarket custom machining services would be the only options for repair. This was the case in 2007 when a discharge valve seat failed, resulting in catastrophic damage to cylinder 611. An extensive search across the used parts dealers was required to secure a viable used cylinder head. Other internal damage was repaired through custom machining services.

Justification: In the event of a future failure, if useable parts or custom machining are not available, the two options would be custom-designed aftermarket castings (if possible) or replacement of the entire compressor. However, both options would render the compression out of service for at least one operational season.

Assets: Waubuno Compressor

Related Programs: N/A

Recommended Alternative Description

Scope of Work: This project includes constructing 6.5 kilometres of NPS 16 wil between the Waubuno pool measurement station and the Bluewater, Airport, & Mandaumin NPS16 pipeline. The high-pressue pipe links Waubuno directly to Dawn compression. This results in increased operational flexibility, reduced cycle time and increased reliability.

Resources:
Consultant resources for design
Contractor resources for abandonment, construction and commissioning

Solution Impact:
New pipeline designed to meet injection requirements provided by compression.

Project Timing and Execution Risk:
This project requires two years of design, procurement, and construction and requires an environmental assessment and regulatory approval.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Compression Stations - Replacements
Investment Stage	Long Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_53 - Union South Storage
	Asset Program (EGI)	CS - Replacements
	Asset Class (EGI)	Compression Stations
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
NPS 16 Pipeline	Recommended	$ (6,150,055)	0.35	$ 12,889,800	1/1/2023

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ -	$ -	$ 867,043	$ 11,540,651	$ 482,106
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Investment Summary Report	Investment Code	Report Start Year	Number of Years
	48732	**2021**	**5**
	Investment Name		
	Waubuno Compression Lifecycle		

Alternative Value - Recommended

	Value Function Measure	Value	Value in Percentage
	Financial Risk	14,015	52%
	Revenue Impact (CA)	3,349	12%
	Cost Avoidance CAPEX (CA)	0	0%
	Cost Avoidance OPEX (CA)	0	0%
	Budget Savings CAPEX (CA)	0	0%
	Budget Savings OPEX (CA)	0	0%
	Total Investment Cost (CA)	(9,499)	35%
	Total	**7,865**	**100%**

Transmission Pipe and Underground Storage

Investment Code	Report Start Year	Number of Years
48654	**2021**	**5**

Investment Summary Report

Investment Name

Dawn Parkway Expansion Project (Kirkwall-Hamilton NPS 48)

Investment Description

Issue/Concern:
Incremental capacity is required on the Dawn Parkway System to meet in-franchise growth and customer demand bids received in the 2021/2022 Dawn Parkway Open Season from December 2018. All incremental demand bids are for 15 year terms with start dates of both November 1, 2021 and 2022.

This is an ICM-eligible project.

Assets: Dawn Parkway System Transmission Pipeline

Related Program(s): N/A

Recommended Alternative Description

Scope of Work: System Install approximately 10.2 kilometres of NPS 48 internally coated pipeline from Kirkwall Valve Site (17V-302) to Hamilton Valve Site (18W-601V) on the Dawn Parkway System.

Solution Impact: Capacity is available on the Dawn Parkway System to meet in-franchise growth and customer demand.

Resources: Projects group to provide project management support from design & planning phase to project execution.

Timing and Execution Risks:
-Proposal is based on Class 4 level cost estimates. There is risk that actual capital costs could exceed the estimate.
-Schedule delays due to right of way access for survey, environmental studies, permitting, and/or issuance of OEB Leave to Construct may put at risk the planned in-service date.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Transmission Pipe & Underground Storage - Growth
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_16 - Hamilton
	Asset Program (EGI)	TPS - Growth
	Asset Class (EGI)	Transmission Pipe & Underground Storage
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (155,052,376)	0.00	$ 181,707,580	1/1/2018

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ -	$ 171,097,289	$ 4,973,539	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended

Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(155,052)	100%
Total	**(155,052)**	**100%**

Investment Code	Report Start Year	Number of Years
48257	**2021**	**5**

ENBRIDGE

Investment Summary Report

Investment Name

INTE: Dawn - Cuthbert - ECDA to ILI Retrofit NPS 42, 34, 26

Investment Description

Issue/Concern:
General concern: The Integrity Management Program is a mandated regulatory requirement which has been designed to comply with all applicable codes and standards. The program consists of the regular assessment and maintenance of the integrity of EGI's pipeline systems to ensure their continued safety and reliability. Most of the expenditure included in this category is for pipelines that operate above 30 per cent SMYS. It includes installation costs for permanent in-line inspection (ILI) tool launcher and receiver facilities, retrofits to existing lines to remove restrictive fittings or pipe configurations so they can be inspected with ILI tools, repair and replacement of pipeline segments with integrity issues that are identified through the inspections.

Project-specific concern: The NPS 42, NPS 34, NPS 26 pipelines between Dawn Compressor station and Cuthbert Road receiver site has been inspected using external corrosion direct assessment (ECDA). Although it meets the intent of the TIMP, there are specific features that ECDA could not detect comparing to the inline inspection. ILI of these transmission lines are required to ensure continued safety and reliability of EGI's assets.

Assets: Transmission Pipeline (NPS 42, NPS 34, NPS 26 pipelines between Dawn Compressor station and Cuthbert Road receiver site)

Related Programs: Transmission Integrity Management Program (TIMP)

Recommended Alternative Description

Scope of Work: This project involves the replacement and conversion of transmission pipelines, so that they can be inline inspected between Trafalgar Valve Nest (TVN) at Dawn and the Cuthbert Measurement site.

Solution Impact: This project will enable the transmission pipelines between Dawn and Cuthbert to be in-line inspected to assess their condition.

Resources: Projects group to provide project management support from design and planning phase to project execution

Project Timing and Execution Risks: The projected in-service date for this project is in 2022.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Transmission Pipe & Underground Storage- Integrity
Investment Stage	Short Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_53 - Union South Storage
	Asset Program (EGI)	TPS - Integrity
	Asset Class (EGI)	Transmission Pipe & Underground Storage
2. Compliance	Compliance Investment	Yes
	Compliance Justification & Code	Required as per CSA Z662. (Sections 3.2, 10.3) and stipulated through EGD standards as listed in Integrity Manual Section 4.2.6.1.10 In-Line Inspection Re-Inspection Interval.
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (21,559,122)	0.00	$ 24,600,000	1/1/2021

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 1,000,000	$ 23,600,000	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended

Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(21,559)	100%
Total	**(21,559)**	**100%**

Investment Summary Report

Investment Code	Report Start Year	Number of Years
100086	2021	5

Investment Name

Panhandle Line Replacement

Investment Description

Issue/Concern:
EGI's Integrity Management team initiated work in 2019 to better understand the risk associated with the two NPS12 crossings that connect the Panhandle Eastern System owned and operated by Energy Transfer in Michigan with the EGI system in Ontario. These two crossings, installed in 1947, have never been inspected internally to provide direct assessment of the asset and to check for the presence of the primary threat of corrosion. A risk assessment was recently completed for the river crossings. The Risk Owner and Risk Approver reviewed the risk results and have decided the risk requires treatment with a permanent solution.

Assets: Transmission Pipeline (CER regulated crossing)

Related Programs: N/A

Recommended Alternative Description

Scope of Work: Replacement of the twin NPS 12 Crossings with a new NPS 20 pipeline.

Resources: Projects group to provide project management support from design & planning phase to project execution.

Solution Impact: The principal risk is the lack of ILI data needed to inform effective decision-making to mitigate a potential loss of pipeline containment (leak). Replacement with a new single pipeline, designed, manufactured and constructed to current standards that is ILI-capable can address this risk.

Project Timing and Execution Risk: In-service date is estimated to be Q3 2023. Overall project schedule highly dependent on regulatory process and discussion with joint partner (Energy Transfer).

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Transmission Pipe & Underground Storage - Replacements
Investment Stage	Short Term Planning		

Investment Overview

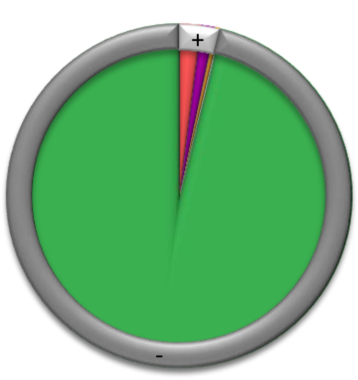
1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_01 - Windsor
	Asset Program (EGI)	TPS - Replacements
	Asset Class (EGI)	Transmission Pipe & Underground Storage
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	Yes
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 2 - Replacement	Recommended	$ (23,536,717)	0.00	$ 29,771,279	1/1/2022

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ -	$ 1,619,900	$ 24,757,660	$ 3,393,719	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Operational Disruption Risk (Gas) (CA)	481	2%
Financial Risk	311	1%
Environmental Risk And Remediation	104	0%
Reputational Risk	45	0%
Public Safety Risk	0	0%
Employee And Contractor Safety Risk	0	0%
Total Investment Cost (CA)	(23,537)	96%
Total	**(22,595)**	**100%**

ENBRIDGE Investment Summary Report	Investment Code **48658**	Report Start Year **2021**	Number of Years **5**
	Investment Name Sarnia Expansion - Bluewater Energy Park (Asset #1)		

Investment Description

Issue/Concern:
EGI is forecasting 150 TJ/d of firm transportation growth primarily driven by industrial demand in Sarnia and surrounding areas requiring incremental Sarnia Industrial Line (SIL)System capacity.

Assets: SIL System Transmission Pipeline

Related Programs: 48659, 48660

Recommended Alternative Description

Scope of Work:
-Installation of ~7 kilometres of NPS 24/30 pipeline from existing LaSalle Pipeline Valve Site to Churchill Road Station (13F-503).
-Installation NPS 20 pipeline to a new multi-customer valve site in Bluewater Energy Park.

Resources: Projects group to provide project management support from design and planning phase to project execution.

Solution Impact:
Facilities will allow the SIL System to efficiently serve ~150 TJ/d demand and provide security of supply for the SIL System.

Project Timing and Execution Risks:
-Proposal is based on Class 5 level cost estimates. There is risk that actual capital costs could exceed the estimate.
-Schedule delays due to right of way access for survey, environmental studies, permitting, and/or issuance of an OEB Leave to Construct may put the planned in-service date at risk.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Transmission Pipe & Underground Storage - Growth
Investment Stage	Long Term Planning		

Investment Overview

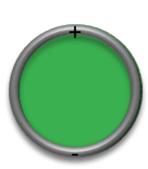
1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_54 - Head Office Support
	Asset Program (EGI)	TPS - Growth
	Asset Class (EGI)	Transmission Pipe & Underground Storage
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (47,468,659)	0.00	$ 64,568,088	1/1/2021

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 281,562	$ 281,562	$ 2,377,968	$ 58,606,438	$ 2,940,670
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(47,469)	100%
Total	**(47,469)**	**100%**

ENBRIDGE Investment Summary Report	Investment Code	Report Start Year	Number of Years
	48660	2021	5
	Investment Name: Sarnia Expansion - Bluewater Energy Park (Asset #2)		

Investment Description

Issue/Concern:
EGI is forecasting 150 TJ/d of firm transportation growth primarily driven by industrial demand in Sarnia and surrounding areas requiring incremental Sarnia Industrial Line (SIL) System capacity.

Assets: SIL System Transmission pipeline

Related Programs: 48658, 48659

Recommended Alternative Description

Scope of Work:
Requires 1.5 kilometres of NPS 24 Pipeline between the Dawn Hub & SIL System.

Solution Impact:
Facilities will allow the SIL System to efficiently serve ~150 TJ/d demand and provide security of supply for the SIL System.

Resources: Projects group to provide project management support from design and planning phase to project execution.

Project Timing and Execution Risks:
-Proposal is based on Class 5 level cost estimates. There is risk that actual capital costs could exceed the estimate.
-Schedule delays due to right of way access for survey, environmental studies, permitting, and/or issuance of an OEB Leave to Construct may put the planned in-service date at risk.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Transmission Pipe & Underground Storage - Growth
Investment Stage	Long Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_54 - Head Office Support
	Asset Program (EGI)	TPS - Growth
	Asset Class (EGI)	Transmission Pipe & Underground Storage
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (25,113,150)	0.00	$ 34,000,000	1/1/2022

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ -	$ 500,000	$ 1,500,000	$ 31,500,000	$ 500,000
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended

Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(25,113)	100%
Total	**(25,113)**	**100%**

Investment Code	Report Start Year	Number of Years
48659	**2021**	**5**

ENBRIDGE

Investment Summary Report

Investment Name

Sarnia Expansion - Bluewater Energy Park (Customer Station)

Investment Description

Issue/Concern:
EGI is forecasting 150 TJ/d of firm transportation growth primarily driven by industrial demand in Sarnia and surrounding areas requiring incremental Sarnia Industrial Line (SIL) System capacity.

Assets: Transmission Pipeline

Related Programs: 48658, 48660

Recommended Alternative Description

Scope:
Install a new NPS 16 service line with a new customer station.

Solution Impact:
Facilities will allow the SIL System to efficiently serve ~150 TJ/d demand.

Resources: Projects group to provide project management support from design and planning phase to project execution.

Project Timing and Execution Risks: Proposal is based on Class 5 level cost estimates. There is a risk that actual capital costs could exceed the estimate. Schedule delays due to right of way access for survey, environmental studies, permitting, and/or issuance of an OEB Leave to Construct may put the planned in-service date of Nov ember1, 2021 at risk.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Transmission Pipe & Underground Storage - Growth
Investment Stage	Long Term Planning		

Investment Overview

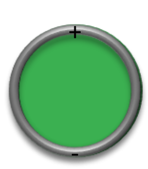
1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_03 - Sarnia
	Asset Program (EGI)	TPS - Growth
	Asset Class (EGI)	Transmission Pipe & Underground Storage
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (8,599,463)	0.00	$ 11,730,139	1/1/2022

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ -	$ 10,110	$ 31,853	$ 11,217,088	$ 471,088
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(8,599)	100%
Total	**(8,599)**	**100%**

Investment Summary Report	Investment Code	Report Start Year	Number of Years
	48661	2021	5
	Investment Name: Sarnia Expansion (Novacor Stn)		

Investment Description

Issue/Concern:
Enbridge Gas is forecasting 61.4 TJ/d of firm transportation growth primarily driven by industrial demand in Sarnia and surrounding areas to serve NOVA Chemicals (Canada) T2 growth for a November 1, 2021 in-service date.

Assets: Transmission Pipeline - customer station

Related Programs: 48657

Recommended Alternative Description

Scope of Work:
1.Novacor Corunna customer station modifications (12F-203I)
2.Novacor Corunna station modifications (12F-203)

Resources:
Projects group to provide project management support from design and planning phase to project execution.

Solution Impact:
Facilities will allow the Sarnia Industrial Line System to efficiently serve NOVA Chemicals (Canada) T2 growth (~61.3 TJ/d) demand for a November 1, 2021 ISD.

Project Timing and Execution Risks:
-Proposal is based on Class 4 level cost estimates. There is risk that actual capital costs could exceed the estimate.
-Schedule delays due to right of way access for survey, environmental studies, permitting, and/or issuance of OEB Leave to Construct may put at risk the planned in-service date of November 1, 2021.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Transmission Pipe & Underground Storage - Growth
Investment Stage	Executing		

Investment Overview

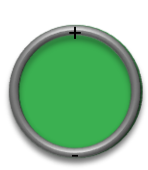
1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_54 - Head Office Support
	Asset Program (EGI)	TPS - Growth
	Asset Class (EGI)	Transmission Pipe & Underground Storage
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (6,035,064)	0.00	$ 6,515,656	1/1/2020

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 6,421,822	$ 34,357	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(6,035)	100%
Total	**(6,035)**	**100%**

ENBRIDGE **Investment Summary Report**	Investment Code **48657**	Report Start Year **2021**	Number of Years **5**
	Investment Name Sarnia Expansion (NPS 20 Dow to Bluewater)		

Investment Description

Issue/Concern:
EGI is forecasting 61.4 TJ/d of firm transportation growth primarily driven by industrial demand in Sarnia and surrounding areas to serve NOVA Chemicals (Canada) T2 growth for a November 1, 2021 in-service date requiring incremental Sarnia Industrial Line (SIL) system capacity.

This is an ICM-eligible project.

Assets: Transmission Pipeline

Related Programs: 48661

Recommended Alternative Description

Scope of Work: One NPS 20 pipeline reinforcement from existing Dow valve site (13F-501V) to existing Bluewater / Union Interconnect valve site (13F-502V)

Solution Impact:
Facilities will allow the SIL System to efficiently serve NOVA Chemicals (Canada) T2 growth (~61.3 TJ/d) demand for a November 1, 2021 in-service date.

Resources:
Projects group to provide project management support from the design and planning phase to project execution.

Project Timing and Execution Risks:
- Proposal is based on Class 4 level cost estimates. There is risk that actual capital costs could exceed the estimate.
- Schedule delays due to right of way access for survey, environmental studies, permitting, and/or issuance of an OEB Leave to Construct may put the planned in-service date of November 1, 2021 at risk.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Transmission Pipe & Underground Storage - Growth
Investment Stage	Executing		

Investment Overview

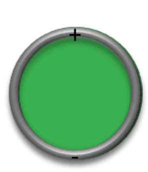
1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_54 - Head Office Support
	Asset Program (EGI)	TPS - Growth
	Asset Class (EGI)	Transmission Pipe & Underground Storage
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (18,987,323)	0.00	$ 20,480,786	1/1/2020

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 18,161,923	$ 1,038,370	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(18,987)	100%
Total	**(18,987)**	**100%**

Investment Summary Report	Investment Code	Report Start Year	Number of Years
	48215	2021	5
	Investment Name: Trafalgar 26 - Branchton Class Location Replacement		

Investment Description

Issue/Concern:
General: Annual Class Location surveys are required as per the Canadian Standards Association Z662 – Oil and Gas Pipeline Systems for pipelines greater than 30 per cent SMYS. Any changes in class location need to be assessed to the current standard to determine if pipeline modifications are required. This program replaces segements of pipelines with identified Class Location Change.

Project Specific: Replacement of 1.8 kilometres of NPS 26 pipe including pipe under Branchton Road (Regional Road 43).

Assets: 1.8 kilometres of NPS 26 pipe

Related Programs: N/A

Recommended Alternative Description

Scope of Work: Replace 1.8 kilometres of NPS 26 pipe.

Solution Impact: Remediate class location issue of the NPS 26 Dawn-Parkway transmission line near Branchton.

Resources: Engineering Construction group to provide project management support from design and planning phase to project execution

Timing and Execution Risks:
-Proposal is based on Class 5 level cost estimates. There is risk that actual capital costs could exceed the estimate.
-The Leave to Construct application and land right acquisition could have timing implications.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Transmission Pipe & Underground Storage - Replacements
Investment Stage	Executing		

Investment Overview

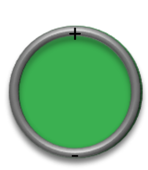
1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_54 - Head Office Support
	Asset Program (EGI)	TPS - Replacements
	Asset Class (EGI)	Transmission Pipe & Underground Storage
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1: Replace class location segment	Recommended	$ (8,115,787)	0.00	$ 8,645,836	1/1/2020

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 7,155,661	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(8,116)	100%
Total	**(8,116)**	**100%**

Real Estate and Workplace Services

Investment Code	Report Start Year	Number of Years
48606	**2021**	**5**

Investment Summary Report

Investment Name

50 Keil Old 2nd Floor Renovations

Investment Description

Issue/Concern: The 50 Keil facility is an owned facility that is currently undergoing renovations to address the physical condition and capacity concerns as well as to replace legacy furniture and finishings.

Physical Obsolescence: The acceptable EGI standard for the physical condition is a Facility Condition Index (FCI) of 0 to 5%. The current FCI of the facility based on this study is 12.91%. Therefore, the physical condition of the facility does not meet EGI acceptable standards.

Functional Obsolescence – Building: The acceptable EGI standard for the functional condition is 0%. A functional condition between 0 and 49% is considered correctable at the current location. The current facility Adequacy Index (AI) is 11% which is considered correctable at the current location, without consideration of other factors including adequacy of land size and the FCI.

Functional Obsolescence – Site: N/A

Asset: 50 Keil Drive, Chatham, ON.

Related Program: N/A

Recommended Alternative Description

Scope of Work: The project corrects physical and functional deficiencies on the 2nd floor of the old tower by renovating and renewing the existing space. Renovations to the floor will correct operational and workplace inefficiencies, using less energy and emitting less greenhouse gases.

Solution Impact: The interior renovation will extend the asset useful life by 10 to 15 years.

Timing: The total project duration is 12 months and broken down as follows:
0 – 2 months: Programming and design development
2 – 3 months: Permit and tender documents
3 – 5 months: Award, permit and tender process
5 – 10 months: Construction
10 – 12 months: Fit-up and occupancy

Expenditures: The total cost for the project is $4.7 M net capital which includes a working construction cost contingency of 15%. Construction costs are determined based on historical EGI project costs and land values are determined using marketplace comparisons. The project also leverages national pricing agreements with furniture, walls, and flooring manufacturers. The project costs are based on a Class 5 estimate.

Resources : External professional resources for design and engineering along with a construction company will be contracted for the Project. Historically, EGI has retained architectural and engineering consulting services and general construction contractors for the execution of similar projects.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Real Estate & Workplace Services - Furniture/Structures & Improvements
Investment Stage	Short Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_54 - Head Office Support
	Asset Program (EGI)	REWS - Furniture/Structures & Improvements
	Asset Class (EGI)	Real Estate & Workplace Services
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (1,471,316)	0.66	$ 4,700,000	1/1/2021

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 4,700,000	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Investment Code	Report Start Year	Number of Years
48606	2021	5

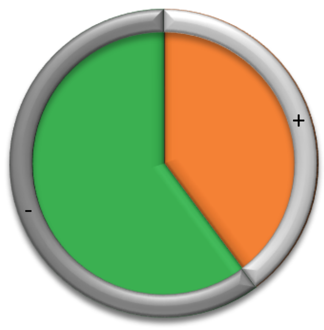
ENBRIDGE

Investment Summary Report

Investment Name

50 Keil Old 2nd Floor Renovations

Alternative Value - Recommended



	Value Function Measure	Value	Value in Percentage
	Cost Avoidance OPEX (CA)	2,881	40%
	Cost Avoidance CAPEX (CA)	0	0%
	Budget Savings CAPEX (CA)	0	0%
	Budget Savings OPEX (CA)	0	0%
	Revenue Impact (CA)	0	0%
	Total Investment Cost (CA)	(4,352)	60%
	Total	**(1,471)**	**100%**

	Investment Code	Report Start Year	Number of Years
ENBRIDGE	**48607**	**2021**	**5**
Investment Summary Report	Investment Name: 50 Keil Old 3rd Floor Renovation		

Investment Description

Issue/Concern: The 50 Keil facility is an owned facility that is currently undergoing renovations to address the physical condition and capacity concerns as well as to replace legacy furniture and finishings.

Physical Obsolescence: The acceptable EGI standard for the physical condition is a Facility Condition Index (FCI) of 0 to 5%. The current FCI of the facility based on this study is 12.91%. Therefore, the physical condition of the facility does not meet EGI acceptable standards.

Functional Obsolescence – Building: The acceptable EGI standard for the functional condition is 0%. A functional condition between 0 and 49% is considered correctable at the current location. The current facility Adequacy Index (AI) is 11% which is considered correctable at the current location, without consideration of other factors including adequacy of land size and the FCI.

Functional Obsolescence – Site: N/A

Asset: 3rd floor, 50 Keil Drive, Chatham, ON.

Related Program: N/A

Recommended Alternative Description

Scope of Work: The project corrects physical and functional deficiencies on the third floor of the old tower by renovating and renewing the existing space. Renovations to the floor will correct operational and workplace inefficiencies, using less energy and emitting less greenhouse gases.

Solution Impact: The interior renovation will extend the asset useful life by 10 to 15 years.

Timing: The total project duration is 12 months and broken down as follows:
0 – 2 months: Programming and design development
2 – 3 months: Permit and tender documents
3 – 5 months: Award, permit and tender process
5 – 10 months: Construction
10 – 12 months: Fit-up and occupancy

Expenditures: The total cost for the project is $4.7 M net capital which includes a working construction cost contingency of 15%. Construction costs are determined based on historical EGI project costs and land values are determined using marketplace comparisons. The project also leverages national pricing agreements with furniture, walls, and flooring manufacturers. The project costs are based on a Class 5 estimate.

Resources : External professional resources for design and engineering along with a construction company will be contracted for the project. Historically, EGI has retained architectural and engineering consulting services and general construction contractors for the execution of similar projects.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Real Estate & Workplace Services - Furniture/Structures & Improvements
Investment Stage	Executing		

Investment Overview

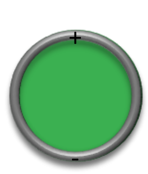
1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_54 - Head Office Support
	Asset Program (EGI)	REWS - Furniture/Structures & Improvements
	Asset Class (EGI)	Real Estate & Workplace Services
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (7,186,343)	0.00	$ 7,537,250	1/1/2020

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 4,737,250	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(7,186)	100%
Total	**(7,186)**	**100%**

Investment Summary Report	Investment Code	Report Start Year	Number of Years
	48693	2021	5
	Investment Name: CS-Belleville PropertyPurch&En*C/O 2019*		

Investment Description

Issue/Concern:
The Belleville Operations Centre is located at 127 Enterprise Drive in Belleville, Ontario in a location that adequately services the Belleville market. The age of the building is not known as it is a leased facility. The facility itself does not satisfy the current operational standards nor does it meet current Ontario Building Code (OBC) requirements.
In 2016, an operational performance assessment was conducted by EGI personnel which identified several deficiencies in the existing facility including but not limited to the inappropriate amount of space, inadequate storage, meeting space and site security, and legacy environmental concerns regarding water quality. The review also found the building to be deficient in several building code and life safety requirements.

Physical Obsolescence: The acceptable EGI standard for physical condition is a Facility Condition Index (FCI) score of 0% to 5%. An FCI score is not available for this facility. However, the physical condition of the facility does not meet EGI standards and is not considered correctable at this location as it is leased space.

Functional Obsolescence - Building: The acceptable EGI standard for functional condition is 0%. Anything between 0% and 50% is considered correctable at the current location. An AI score is not available for this facility. Based on the review, the building does not meet the functional requirements of the business and the conditions are not considered correctable at the current location as it is leased space.

Functional Obsolescence - Site: The site size is unknown. However, the site does not provide adequate traffic control, storage or security. These conditions are not considered correctable at the current location as it is leased space.

Furniture: Legacy furniture (20+ years old) does not meet EGI's current condition standards. At this facility, 53% of the furnishings are considered legacy and therefore not compliant with current standards.
The building and site deficiencies are numerous, and considered not correctable at this location due to the fact that this is a leased property.

Assets: Belleville Operations Centre located at 127 Enterprise Drive in Belleville, Ontario.

Related Programs: N/A

Recommended Alternative Description

Scope of Work:
Vacate current leased facility, purchase new property in Belleville (four acres) and build a new facility on the new site.

Resources: Company crews, contractor labour, and third-party vendor suppliers.

Solution Impact:
There are a number of consequences to EGI if the deficiencies at Belleville are not corrected. These include but are not limited to:
- Higher operating costs and increased Greenhouse Gas (GHG) emissions due to inefficient equipment and building systems.
- Potential of injury, illness or fatality as the building does not conform to the current OBC life safety, barrier-free and universal design standards.
- Inadequate functionality resulting in productivity challenges for staff and visitors.

Timing and Execution Risks:
The Project duration is 36 months:
0 – 3 months: Programming, design development
3 – 6 months: Site acquisition
6 – 12 months: Site plan agreement, permit and tender documents, permit and tender process
12 – 14 months: Contract award and winter contingency as required
14 – 28 months: Construction
28 – 30 months: Fit-up and occupancy
30 – 36 months: Disposition of old property

Risks include contractor delays and material delivery delays or defects, weather impacts, resource availability, procurement issues, etc.

Expenditures:
The total cost for the project is $7.5 M net capital which includes a working construction cost contingency of 15%. Construction costs are determined based on historical EGI project costs and estimated land values are based on marketplace comparisons. The project also leverages national pricing agreements with furniture, walls, and flooring manufacturers. The project costs are based on a Class 5 estimate.

External professional resources for design and engineering along with a construction company will be contracted for the project. Historically, EGI has retained architectural and engineering consulting services and general construction contractors for the execution of similar projects.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Real Estate & Workplace Services - Furniture/Structures & Improvements
Investment Stage	Executing		

ENBRIDGE **Investment Summary Report**	Investment Code **48693**	Report Start Year **2021**	Number of Years **5**
	Investment Name CS-Belleville PropertyPurch&En*C/O 2019*		

Investment Overview

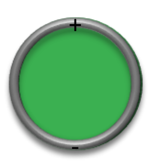
1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_54 - Head Office Support
	Asset Program (EGI)	REWS - Furniture/Structures & Improvements
	Asset Class (EGI)	Real Estate & Workplace Services
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (6,993,599)	0.00	$ 7,500,000	1/1/2020

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 5,833,333	$ 520,833	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(6,994)	100%
Total	**(6,994)**	**100%**

ENBRIDGE Investment Summary Report	Investment Code **100492**	Report Start Year **2021**	Number of Years **5**
	Investment Name Dryden Operations Centre		

Investment Description

Issue/Concern: The administrative office in Dryden is an owned property that is in physically good condition, but does not meet current building standards or operational requirements. The physical condition is considered poor and the utilization and functionality is challenged. The office space no longer sufficiently accommodates current and future staffing needs of the facility.

Physical Obsolescence: The acceptable EGI standard for the physical condition is a Facility Condition Index (FCI) of 0 to 5%. The current FCI of the facility based on this study is 11.33%. Therefore, the physical condition of the facility does not meet EGI acceptable standards.

Functional Obsolescence – Building: The acceptable EGI standard for the functional condition is 0. A functional condition between 0 and 49% is considered correctable at the current location. The current facility Adequacy Index (AI) is 87%.

Functional Obsolescence – Site: The site is serviced by one driveway off Kennedy Road. There is no separation of staff parking, visitor parking or yard. This is considered a safety and operational challenge. No trucks or fleet vehicles were observed parking in the yard. No pipe racks were observed. A material storage building is located to the south of the main building.
The following programmatic and functional deficiencies were observed during the walkthrough:
- There is no secure yard separated from staff and visitor parking.
- There is no site security present, including site fencing, access gates, yard perimeter lighting and security cameras.
- The yard storage is inadequate. Specifically, there are no aggregate storage bins or pipe racks.
- No parking spaces or other lines are marked on the pavement.

The following specific design principles were not met:
- Trucks, fleet vehicles, staff, and visitors enter and exit through one driveway.
- Sidewalks are narrow and unevenly paved.

Asset: 304 Kennedy Road, Dryden, ON.

Related Program: N/A

Recommended Alternative Description

Scope of Work: The preferred strategy is to purchase a new property in Dryden (approximately five acres) and build new facility on a new site.
The current facility and yard are too small for the district's current business needs with no room for expansion or growth. The site has inefficient access, configuration and does not meet the current EGI standards.

The assets in scope are located at 304 Kennedy Road, Dryden, ON. The nature of work for the project includes the purchase of a greenfield property approximately five acres, sell the existing and build a new facility to meet the business requirements.

The Project duration is 24 months as described below:
0 – 3 months: Land purchase, Programming and design development
3 – 9 months: Site plan agreement, permit and tender documents
9 – 12 months: Permit and tender process
2 – 14 months: Contract award and contingency as required
14 – 22 months: Construction
22– 24 months: Fit-up and occupancy

Risks include contractor delays and material delivery delays or defects.

Expenditures:
The total cost for the project is $4.6M net capital which includes a working construction cost contingency of 15%. Construction costs are determined based on historical EGI projects. The project also leverages national pricing agreements with furniture, walls and flooring manufacturers. The project costs are based on a Class 4 estimate.

Resources
Professional resources for design and engineering will be contracted from the marketplace. Historically, EGI has retained architectural and engineering consulting services for the execution of similar projects.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Real Estate & Workplace Services - Furniture/Structures & Improvements
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_33 - Thunder Bay
	Asset Program (EGI)	REWS - Furniture/Structures & Improvements
	Asset Class (EGI)	Real Estate & Workplace Services
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Investment Code	Report Start Year	Number of Years
100492	2021	5

Investment Name

Dryden Operations Centre

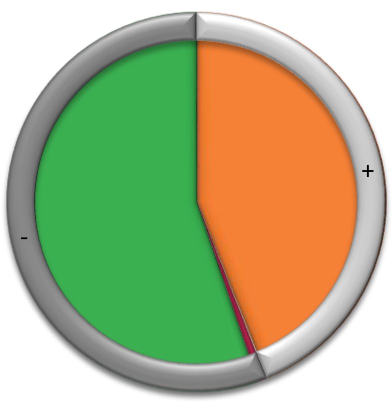
Investment Summary Report

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (726,942)	0.80	$ 3,850,000	1/1/2020

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 3,000,000	$ 500,000	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Cost Avoidance OPEX (CA)	2,830	44%
Cost Avoidance CAPEX (CA)	0	0%
Budget Savings CAPEX (CA)	0	0%
Budget Savings OPEX (CA)	0	0%
Revenue Impact (CA)	0	0%
Avoided GHG Emissions (CA)	(8)	0%
Energy Efficiency (CA)	(47)	1%
Total Investment Cost (CA)	(3,556)	55%
Total	**(781)**	**100%**

	Investment Code	Report Start Year	Number of Years
ENBRIDGE **Investment Summary Report**	**101136**	**2021**	**5**
	Investment Name: New Site No. 4		

Investment Description

This project will allow for potential consolidation currently under review of four operational sites in the Union rate zones into a single facility.
Boundary analysis still ongoing and investment details will continually be updated as strategy progresses.

Functional Obsolescence – Building: N/A

Functional Obsolescence – Site: N/A

Assets: N/A

Related Program: N/A

Recommended Alternative Description

Scope of Work:
This project requires selling existing assets, purchasing a property suitable in size (approx. 7-10 acres) and building a new 44,000 sq. ft. building that will consist of administration, warehouse, welding and fabrication facilities. The preferred strategy is to correct physical and functional deficiencies by purchasing a new site and build a new facility on the new site.

Solution Impact: This option corrects operational and workplace inefficiencies by consolidating existing facilities. The new facility will use less energy and emit less greenhouse gases. The service life for the new facility will be 25-40 years.

Timing: The total project duration is 30 months:
0 – 3 months: Programming, design development, location analysis
3 – 6 months: Site acquisition
6 – 12 months: Site plan agreement, permit and tender documents, permit and tender process
12 – 14 months: Contract award and winter contingency as required
14 – 28 months: Construction
28 – 30 months: Fit-up and occupancy
Post-occupancy disposition of property

Risks include contractor delays and material delivery delays or defects.

Expenditures:
The total cost for the project is $28.8M net capital which includes a working construction cost contingency of 15%. Construction costs are determined based on historical EGI project costs and land values using marketplace comparisons. The project also leverages national pricing agreements with furniture, walls, and flooring manufacturers. The project costs are based on a Class 5 estimate.

Resources: External professional resources for design and engineering along with a construction company will be contracted for the project. Historically, EGI has retained architectural and engineering consulting services and general construction contractors for the execution of similar projects.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Real Estate & Workplace Services - Furniture/Structures & Improvements
Investment Stage	Short Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_46 - North Bay & Orillia
	Asset Program (EGI)	REWS - Furniture/Structures & Improvements
	Asset Class (EGI)	Real Estate & Workplace Services
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (19,338,724)	0.22	$ 28,800,000	1/1/2021

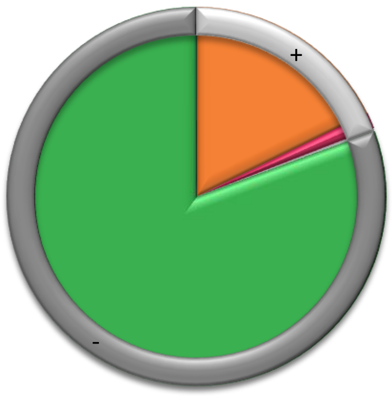
Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 10,000,000	$ 10,000,000	$ 8,800,000	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Investment Summary Report	Investment Code	Report Start Year	Number of Years
	101136	2021	5

Investment Name

New Site No. 4

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Cost Avoidance OPEX (CA)	5,480	18%
Energy Efficiency (CA)	423	1%
Avoided GHG Emissions (CA)	69	0%
Cost Avoidance CAPEX (CA)	0	0%
Budget Savings CAPEX (CA)	0	0%
Budget Savings OPEX (CA)	0	0%
Revenue Impact (CA)	0	0%
Total Investment Cost (CA)	(24,818)	81%
Total	**(18,847)**	**100%**

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
100607	**2021**	**5**

Investment Name

Thunder Bay Regional Operations Centre

Investment Description

Issue/Concern: The Thunder Bay depot on Amber Drive is an owned property in a good location. The physical and functional conditions of the building are considered good, but the utilization and functionality of the site is challenged.

Physical Obsolescence: The acceptable EGI standard for the physical condition is a Facility Condition Index (FCI) of 0 to 5%. The current FCI of the facility based on this study is 2.57%. Therefore, the physical condition of the facility meets EGI acceptable standards.

Functional Obsolescence – Building: The acceptable EGI standard for the functional condition is 0. A functional condition between 0 and 49% is considered correctable at the current location. The current facility Adequacy Index (AI) is 41%.

Functional Obsolescence – Site: The yard is smaller than EGI standard (2.5 acres), at approximately 1.86 acres. The building is serviced by a main entrance off Amber Drive through a circular drop off-area that leads to visitor and staff parking. An appropriate landscape buffer has been provided between the parking areas and building. The main entrance to the yard is provided off Amber Drive, with a power accessed gate. A chain-link fence meeting EGI's standard height requirements surrounds the perimeter of the yard. A secondary site entrance is provided through a northern driveway that leads to additional parking and yard access, with gates at the northern and southern boundaries. Pedestrian entries/exits are provided at the southern gate. Surveillance, security, storage and safety items located on the site all were observed to be in good condition and meet current EGI standards.

Asset: 1211 Amber Drive, Thunder Bay, ON.

Related Program: N/A

Recommended Alternative Description

Scope of Work: Correct physical and functional deficiencies by renovating the existing facility.
The renovation will ensure adequate interior storage/warehouse space for operations, operations meeting space, washroom/locker facilities appropriately fitted for the operation, and a new office environment for staff at site. The program will include currently missing elements such as a boot wash with washer/dryer, mustering area, hoteling, and gas monitor calibration facilities. This new facility will correct operational and workplace inefficiencies, using less energy and emitting less greenhouse gases.

Solution Impact: The renovation will extend the asset useful life by 15 years.

Timing: The Project duration is 12 months as described below:
0 – 2 months: Programming and design development
2 – 5 months: Permit and tender documents
5 – 7 months: Award, tender and permit process
7 – 11 months: Construction
11 – 12 months: Fit-up and occupancy

Risks include contractor delays and material delivery delays or defects.

Expenditures:Total capital expenditure for this project is estimated to be $10.2M which includes a working construction cost contingency of 15%. Construction costs are determined based on historical EGI project costs. The project also leverages national pricing agreements with furniture, walls, and flooring manufacturers. Project costs are based on a Class 5 estimate.

Resources: Professional resources for design and engineering will be contracted from the marketplace. Historically, EGI has retained architectural and engineering consulting services for the execution of similar projects.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Real Estate & Workplace Services - Furniture/Structures & Improvements
Investment Stage	Short Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_33 - Thunder Bay
	Asset Program (EGI)	REWS - Furniture/Structures & Improvements
	Asset Class (EGI)	Real Estate & Workplace Services
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (3,038,944)	0.56	$ 10,200,000	1/1/2024

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ -	$ -	$ -	$ 600,000	$ 9,600,000
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

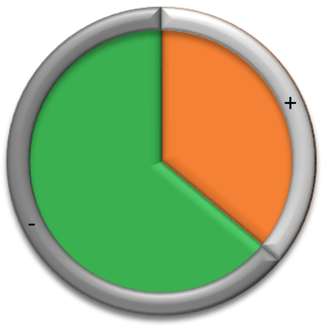
Investment Summary Report

Investment Code	Report Start Year	Number of Years
100607	2021	5

Investment Name

Thunder Bay Regional Operations Centre

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Cost Avoidance OPEX (CA)	3,936	36%
Cost Avoidance CAPEX (CA)	0	0%
Budget Savings CAPEX (CA)	0	0%
Budget Savings OPEX (CA)	0	0%
Revenue Impact (CA)	0	0%
Total Investment Cost (CA)	(6,975)	64%
Total	**(3,039)**	**100%**

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
102392	2021	5

Investment Name

Union Rate Zones Micro Operations Sites Program

Investment Description

Issue/Concern:
The 16 Micro Operations Sites Program covers consist of 15 owned and one leased property. The sites are in aging physical condition, and due to their advanced age, do not meet required functionality. The properties are on average over 50 years old. The physical condition of the facilities does not meet EGI acceptable standards.

Generally, deficiencies are considered correctable at the current locations, without consideration of other factors including adequacy of land size and the Facilities Condition Index (FCI). Generally, the existing buildings are too small to meet current requirements. The undersized spaces, lack of proper locker/washroom, warehouse and fabrication areas are not sufficient for staff and cause operational and workplace difficulties and inefficiencies. Building expansions on the same property may further reduce the size of yard area, making it unusable and will impose additional pressure on parking and circulation.

Assets:
Micro Operations sites in Bracebridge, Haileybury, Huntsville, Iroquois Falls, Black River, Elliot Lake, Parry Sound, Atikokan, Kirkland Lake, Kapuskasing, Hearst, Geraldton, Englehart, Cochrane, Palmerston and Nipigon.

Related Programs: N/A

Recommended Alternative Description

Scope of Work: The project corrects physical and functional deficiencies of the 16 properties by renovating and renewing the existing space. The current site has capacity to meet EGI functional requirements. Renovations to the buildings will correct operational and workplace inefficiencies, using less energy and emitting less greenhouse gases.

Solution Impact: The interior renovation will extend the asset useful life by 10 to 15 years.

Timing: The total project duration is 60 months and is recurring.

Expenditures: The total cost for the project is $10M net capital which includes a working construction cost contingency of 15%. Construction costs are determined based on historical EGI project costs and land values are determined using marketplace comparisons. The project also leverages national pricing agreements with furniture, walls, and flooring manufacturers. The project costs are based on a Class 5 estimate.

Resources : External professional resources for design and engineering along with a construction company will be contracted for the project. Historically, EGI has retained architectural and engineering consulting services and general construction contractors for the execution of similar projects.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Real Estate & Workplace Services - Furniture/Structures & Improvements
Investment Stage	Short Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_54 - Head Office Support
	Asset Program (EGI)	REWS - Furniture/Structures & Improvements
	Asset Class (EGI)	Real Estate & Workplace Services
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Default Alternative	Recommended	$ 14,494,855	2.82	$ 10,000,000	1/1/2021

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 2,000,000	$ 2,000,000	$ 2,000,000	$ 2,000,000	$ 2,000,000
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

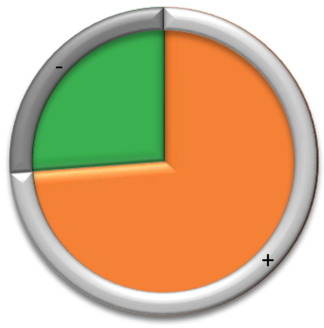
Investment Summary Report

Investment Code	Report Start Year	Number of Years
102392	2021	5

Investment Name

Union Rate Zones Micro Operations Sites Program

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Cost Avoidance OPEX (CA)	22,480	74%
Cost Avoidance CAPEX (CA)	0	0%
Budget Savings CAPEX (CA)	0	0%
Budget Savings OPEX (CA)	0	0%
Revenue Impact (CA)	0	0%
Total Investment Cost (CA)	(7,985)	26%
Total	**14,495**	**100%**

Fleet and Equipment

Investment Code	Report Start Year	Number of Years
102181	**2021**	**5**

Investment Summary Report

Investment Name

2021 - OS - Heavy Work Equipment

Investment Description

Issue/concern: In the Union rate zones, heavy work equipment units which are much older and worn need to be replaced. Individual equipment is assessed using the Fleet Flagship Replace application.

Asset: Various Heavy Duty Equipment assets.

Related Program: N/A

Recommended Alternative Description

Scope of work: This project provides EGI with the necessary heavy work equipment to safely and efficiently run business operations in the Union rate zones. The goal is to maintain the integrity of all heavy work equipment assets for safe and reliable operation. To help achieve this goal, the Fleet department utilizes financial cost, risk analysis, and physical assessment information to drive replacement decisions. As the equipment ages and exceeds its useful life threshold, it can become an operational safety concern. Additionally, there are increases in maintenance costs and operational downtime which affects overall productivity.

Resources: Fleet and Equipment staff

Solution Impact: The fleet management analytical software tool Flagship Replace is used to make informed replacement decisions for rolling equipment such as backhoes. Replacement decisions for non-rolling equipment (i.e. welders) are primarily based on age, hour meter, and physical condition. Once heavy equipment assets reach an age of 10 years, a physical assessment is conducted to evaluate the equipment. A comparison of the maintenance history is used to determine refurbish or replace decisions.

Project Timing and Execution risks: Assets are ordered in January or February of the fiscal year and delivered by December 31.
Risk - delivery of assets not met by the December 31 deadline.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Fleet & Equipment - Equipment & Materials
Investment Stage	Short Term Planning		

Investment Overview

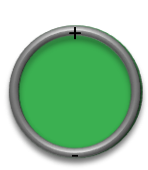
1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_54 - Head Office Support
	Asset Program (EGI)	FLEET - Equipment & Materials
	Asset Class (EGI)	Fleet & Equipment
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	Yes

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (2,827,407)	0.00	$ 3,053,600	1/1/2021

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 3,053,600	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(2,827)	100%
Total	**(2,827)**	**100%**

Investment Summary Report	Investment Code	Report Start Year	Number of Years
	102060	2021	5
	Investment Name: 2021 - OS - Transportation-Replacements		

Investment Description

Issue/Concern: In the Union rate zones, light and medium duty vehicles are required to replace existing vehicles that are in poor operating condition.

Asset: Light-duty vehicles and medium-duty vehicles.

Related Program: N/A

Recommended Alternative Description

Scope of work: This project provides EGI with the necessary fleet vehicles to safely and efficiently run its business operations in the Union rate zones. The goal of the project is to maintain the integrity of all fleet assets for safe and reliable operation. This ongoing replacement strategy optimizes the asset life cycle, improves safety, and reduces risk for EGI and its employees. To help achieve this goal, Fleet utilizes financial cost analysis, risk analysis, and physical asset assessment to guide replacement decisions.

Resources: Fleet and Equipment staff

Solution Impact: In order to replace aging fleet assets, a report is generated by the fleet management analytical software tool which uses raw fleet data to identify all vehicles meeting the replacement criteria. The direct impact is reduced O&M repair and maintenance costs, and improved driver safety.

Project Timing and Execution risks: Assets are ordered in January or February of fiscal year and delivered by December 31.
Risk - delivery of assets not met by the December 31 deadline.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Fleet & Equipment - Vehicles
Investment Stage	Short Term Planning		

Investment Overview

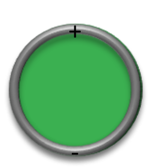
1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_54 - Head Office Support
	Asset Program (EGI)	FLEET - Vehicles
	Asset Class (EGI)	Fleet & Equipment
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	Yes

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (4,580,000)	0.00	$ 4,946,400	1/1/2021

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 4,946,400	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(4,580)	100%
Total	**(4,580)**	**100%**

Technology and Information Services

Investment Code	Report Start Year	Number of Years
102292	2021	5

ENBRIDGE

Investment Summary Report

Investment Name

Nominations Application Replacement (2024-2025)

Investment Description

Issue/Concern/Opportunity:
The Classification, Allocation, Reporting and Exchange (CARE) application is ~25 years old. To mitigate risk of failure and to ensure it is on a supportable technology platform, a replacement/modernization project needs to be initiated.
The CARE application is EGI's gas nominations and scheduling system. It processes both incoming nominations:
- EGI as a service provider to various customer groups and outgoing nominations
- EGI as a shipper on upstream pipelines to bring gas supply to Ontario

CARE checks all nominations against the related contract parameters to ensure the validity of each nomination as well as ensuring that EGI's system is balanced every gas day. CARE supports NAESB nomination cycles, TCPL STS nomination cycles, and EGI proprietary F24 (firm reserved) nomination cycles. Aggregated scheduled customer nominations are provided to Gas Control at each nomination cycle as a key input to the physical operation of the gas system. CARE also facilitates daily and monthly customer reporting as well as various month end accounting processes such as gas supply invoice verification, wholesale customer billing and gas inventory reconciliation. The CARE application supports both the in-franchise and ex-franchise wholesale business (large contract rate distribution, direct purchase and Storage and Transportation customers) and is deemed the system of record for all gas inventories owned by EGI and third parties. Every molecule of gas that enters or leaves the system, whether owned by EGI or others, is accounted for in CARE on a volumetric basis.
Additionally, GMS uses the CARE application to support the service level agreement that we have with the Energy Fundamentals Group (EFG) to operate their business on their behalf.

Assets: TIS Software (packaged)

Related Investments: N/A

Recommended Alternative Description

Scope of Work:
This project is to replace the CARE application, and must maintain the current functionality and continue to meet the needs of the clients and customers. Initially, solution design will analyze the current custom application, and determine if there is an off-the-shelf packaged application that can address the current capabilities and meet the clients needs ; a determination will be made if this will be a packaged or custom- developed solution. Once the solution has been identified, the project team will enter detailed design, followed by a build and configure phase, QA and testing, and implementation of the solution.

Resources:
TIS PM, TIS BAs, solution architecture, system integrator, vendor services, QA/testing resources

Solution Impact:
Due to the age of the CARE application, a replacement/modernization effort should be undertaken to mitigate risk of system failure. The business estimated the following impacts from a seven-day outage:
1. Money Management: Cash flow, delayed billing: $250 - $500
2. Income/Revenue: Incremental Day to Day S&T Optimization: $2,000 - $5000
3. Re-contracting risk, devalue S&T assets (storage, transport etc, Dawn HUB): $2,000 - $4,000
3. Regulatory/Legal/Contractual: contract breach/non performance, sanctions, fines, lawsuits: $500 - $1,000
4. Cost Overruns - mismanagement of OBA.LBA, Inventory, backstopping: 2,000 - $4,000

Project Timing and Execution Risk:
The project has been identified to begin in 2024 and 2025. The risk of not executing is that this application is extremely old, is increasingly prone to failure, and does not meet the evolving needs of the clients and users.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - TIS - TIS Business Solutions
Investment Stage	Long Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_54 - Head Office Support
	Asset Program (EGI)	TIS Business Solutions
	Asset Class (EGI)	TIS
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Default Alternative	Recommended	$ (17,695,163)	0.00	$ 25,000,000	1/1/2024

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ -	$ -	$ -	$ 12,500,000	$ 12,500,000
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

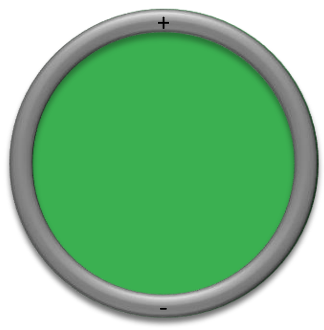
Investment Summary Report

Investment Code	Report Start Year	Number of Years
102292	**2021**	**5**

Investment Name

Nominations Application Replacement (2024-2025)

Alternative Value - Recommended



	Value Function Measure	Value	Value in Percentage
■	Cost Avoidance CAPEX (CA)	0	0%
■	Cost Avoidance OPEX (CA)	0	0%
■	Budget Savings CAPEX (CA)	0	0%
■	Budget Savings OPEX (CA)	0	0%
■	Revenue Impact (CA)	0	0%
■	Total Investment Cost (CA)	(17,695)	100%
	Total	**(17,695)**	**100%**

2020 CUSTOMER ENGAGEMENT RESEARCH ASSET MANAGEMENT PLAN

FEBRUARY 2020
Report

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ENBRIDGE®

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CONTENTS

METHODOLOGY

METHODOLOGY: RESIDENTIAL CUSTOMERS

Asset Management Plan (AMP) Residential Customer Survey

- Overall, n=1,200 Enbridge Gas Inc. residential customers completed the telephone survey between December 5th, 2019 and January 4th, 2020. Within this core sample, n=600 legacy Union Gas and n=600 legacy Enbridge Gas Distribution customers were surveyed. The average interview was 17 minutes in length.
- For the residential segment, survey results have been weighted by age, gender, region, bill type (eBill vs. paper bill), and customer type (either legacy Enbridge Gas vs. legacy Union Gas) to ensure that the sample is representative of the residential customer population of Enbridge Gas Inc. The legacy Enbridge, legacy Union Gas, and total samples have all been weighted separately to reflect their distinct customer bases (as well as the weighted average total customer base).
- Where totals do not add to 100%, it is due either to rounding or the respondent was permitted to provide more than one response.

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METHODOLOGY: BUSINESS CUSTOMERS

Asset Management Plan (AMP) Business Customer Survey

- A total of n=652 Enbridge Gas Inc. non-contract business customers completed either a telephone or online survey. The telephone survey accounted for n=300 of these interviews (n=150 legacy Union Gas and n=150 legacy Enbridge Gas Distribution customers) and was fielded between January 7th and 31st, 2020. The average interview was 16 minutes in length. Non-contract business customers also completed n=352 online surveys, of which n=208 were legacy Union Gas and n=144 were legacy Enbridge Gas Distribution customers. Also, a total of n=70 contract business customers completed an online survey, of which n=47 were legacy Union Gas and n=23 were legacy Enbridge Gas Distribution. The average completion time for the online survey was 10 minutes. The online survey was fielded between January 9th and 28th, 2020.
- For the non-contract business wave, survey results have been weighted by region, bill type (eBill vs. paper bill), and customer type (legacy Enbridge Gas vs. legacy Union Gas) to ensure that the sample is representative of the non-contract business customer population. The legacy Enbridge, legacy Union Gas, and total samples have all been weighted separately to reflect their distinct customer bases (as well as the weighted average total customer base). The contract business sample has not been weighted.
- Where totals do not add to 100%, it is due either to rounding or the respondent was permitted to provide more than one response.

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EXECUTIVE SUMMARY

EXECUTIVE SUMMARY

- Strong majorities of both residential (88%) and business customers (77% non-contract & 79% contract) express satisfaction with the natural gas services they receive from Enbridge Gas Inc. Virtually all customers are satisfied with the safety and reliability of the natural gas service they receive to their home or business, while a majority of residential and business customers are satisfied with the value for money and customer service they receive.
- When asked if Enbridge Gas Inc. should invest in improving or maintaining levels of natural gas safety, reliability, and customer service, the highest proportion of residential customers would prefer that the organization focus on maintaining current levels. This includes about half (53%) of customers who would prefer that Enbridge Gas Inc. maintain existing reliability levels, while slightly fewer than half would prefer to maintain service levels associated with customer service (44%) and safety (43%). The remainder of customers were split between preferring investments in improving levels and answering 'don't know'.
    - A similar proportion of non-contract business customers believe that Enbridge Gas Inc. should maintain existing service levels. Contract business customers are even more likely to prefer that the organization maintain existing service levels associated with safety (71%), reliability (69%) and customer service (53%). Regarding customer service, four in ten (41%) contract business customers would prefer that Enbridge focus on improving customer service.
- Safety, reliability, and affordability are rated as being highly important customer outcomes by business and residential customers. Helping customers become more informed and community-mindedness or social responsibility are rated as the least important. When asked to rank the importance of various aspects of their natural gas service, providing stable and predictable pricing is ranked within the top 4 categories among all customers, while minimizing the impact on the environment is ranked 3rd among residential customers.

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EXECUTIVE SUMMARY

- **Replacing Pipelines and Equipment (In general):** Over half (58%) of residential customers would prefer to spread costs evenly over time, even if it means higher rates now. Fewer residential customers (13%) would prefer that rates are kept low now and to spend only what is necessary on repairs, even if it means a potential increase in rates later on. Three in ten residential customers 'do not have a strong opinion on this' or 'don't know'.
    - Preferences among business customers are similar to residential customers. Contract business customers are slightly more likely to prefer to spread costs evenly over time (63%).
- **Replacing Older Pipelines:** Half (52%) of residential customers would prefer to replace older pipelines all at one time, knowing that for one project example this would translate into an increase of $3 in their natural gas bill per year. One quarter (25%) of customers would prefer to replace older pipelines in phases, which would cost customers an increase of 50 cents in the first year and rise to an increase of $3.50 per year, in five years. Around one in four residential customers 'do not have a strong opinion' or 'don't know' which option they prefer.
    - Preferences for non-contract business customers are evenly split between the two options, with one third of customers preferring to replace older pipelines all at once (36%), while another one third (35%) preferring to replace older pipelines in phases. Contract customers are more likely to prefer to replace pipelines in phases (49%), compared to replacing this pipe all at one time (34%).
- **Bare and Unprotected Pipes:** Among legacy Union Gas customers, slightly more than half (58%) of residential customers, half (49%) of contract business customers, and less than half (41%) of non-contract business customers would prefer that the replacement of bare and unprotected pipes be prioritized, which would increase customer bills by $1 for residential customers and 0.2% for business customers. On the other hand, one in five (21%) residential customers would prefer that these pipes remain in place until they would normally be replaced, 37% of non-contract customers and 28% of contract customers would prefer the same.

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EXECUTIVE SUMMARY

- **Maintenance Operations:** The vast majority of residential (75%), non-contract business (68%), and contract business customers (69%) would prefer that investments in renovating older buildings and building new ones be spread evenly over a longer period of 10 years as opposed to delaying these investments until they can no longer be avoided and funded more quickly, which could cost more in the long run.
- **Fleet Upgrade and Maintenance:** Similarly, a majority of residential (76%), non-contract business (69%) and contract business customers (66%) would prefer that investments for improving fleet vehicles, equipment, and tools be spread out evenly over a longer period of 10 years, compared to delaying such investments until they can no longer be avoided and have to be funded more quickly, which could cost more in the long run.

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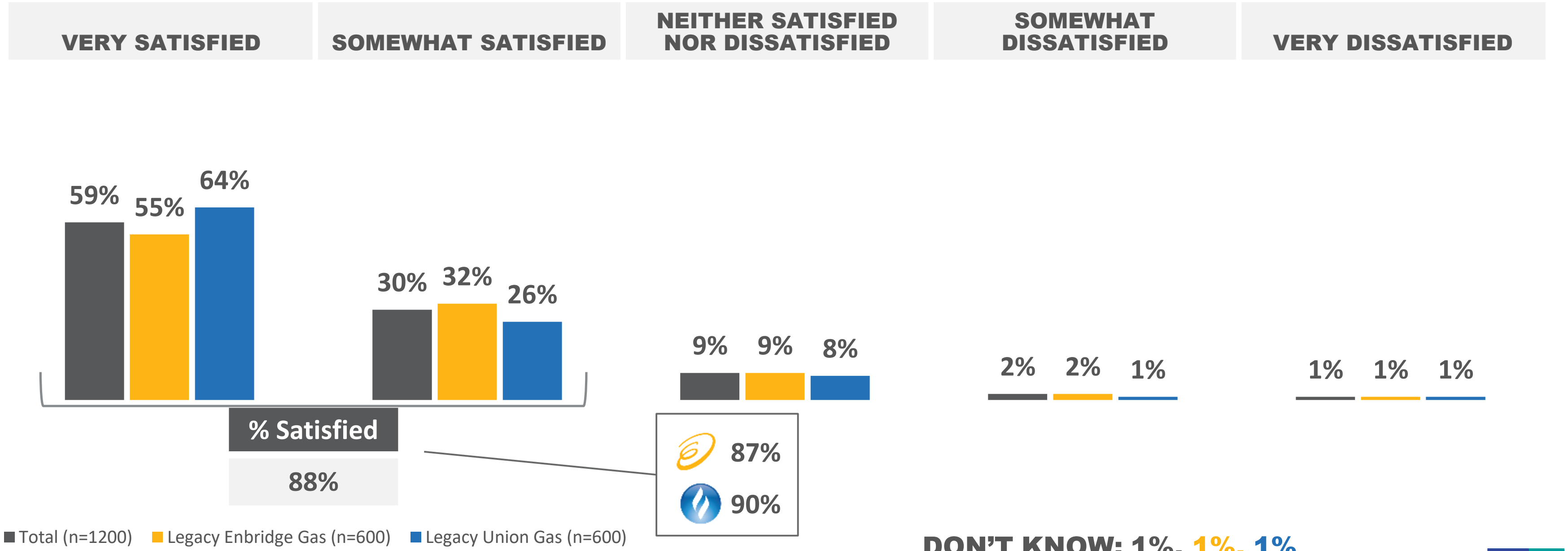
SAFETY, RELIABILITY & CUSTOMER SERVICE

SATISFACTION WITH UTILITY SERVICE: RESIDENTIAL

The vast majority (88%) of residential customers indicate satisfaction with the utility services they receive, including as many as three in five (59%) who say they are ***very satisfied***. Legacy Union Gas customers are more likely to express a high degree of satisfaction (64% *very satisfied*) with these services, compared to their legacy Enbridge Gas (55%) counterparts.

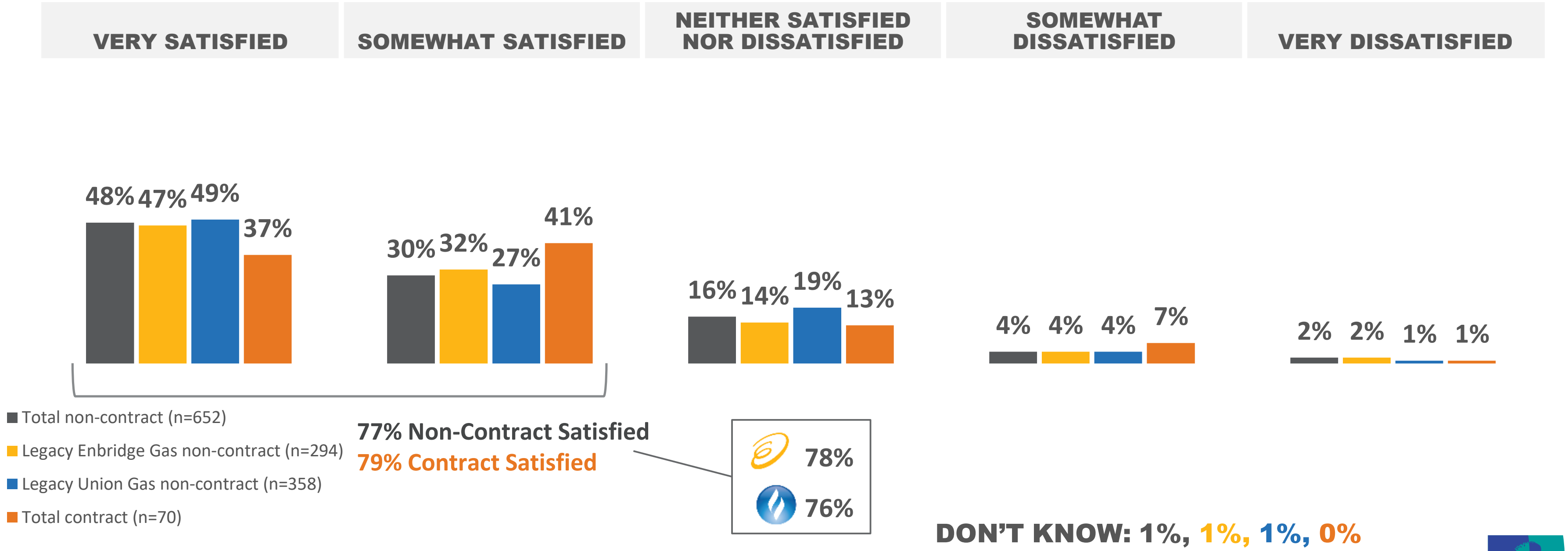


DON'T KNOW: 1%, 1%, 1%

Q2. Taking into consideration all aspects of your utility service experience, how satisfied are you with your [Enbridge Gas / Union Gas, currently operating as Enbridge Gas] service?

SATISFACTION WITH UTILITY SERVICE: BUSINESS

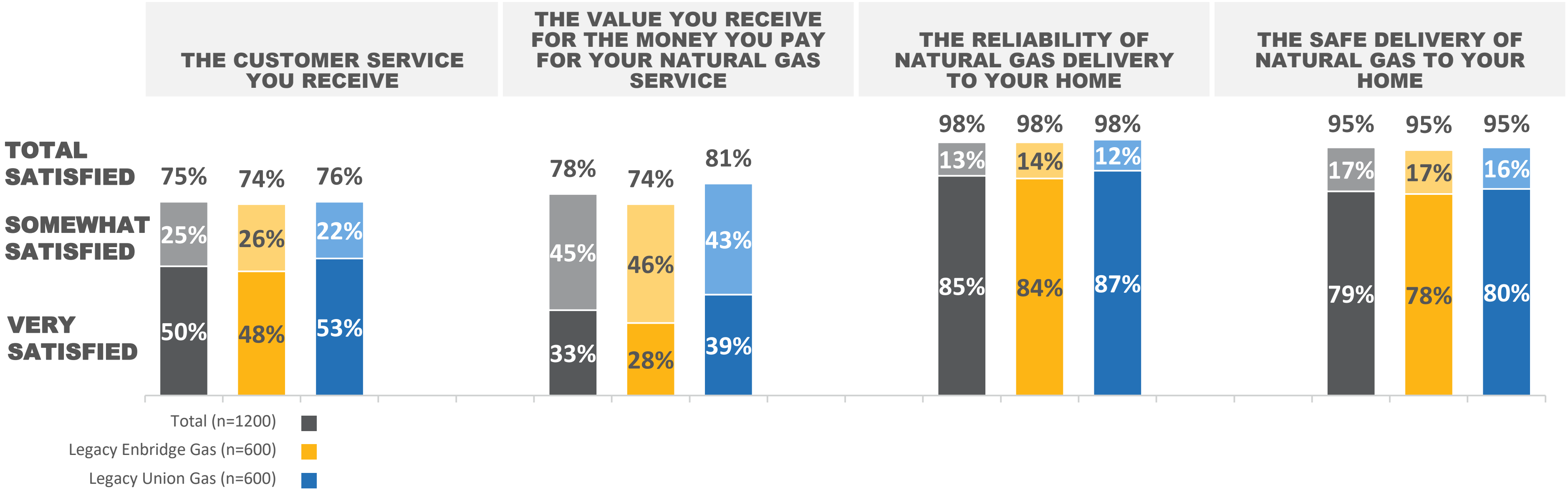
Around three-quarters of non-contract (77%) and contract (79%) business customers are ***satisfied*** with the utility services they are receiving from their natural gas utility. Satisfaction among legacy Enbridge Gas and legacy Union Gas customers is similar as about half these customers indicate that they are 'very satisfied', while contract customers are more likely to indicate that they are 'somewhat satisfied.'



Q2. Taking into consideration all aspects of your organization's utility service experience, how satisfied are you with your [Enbridge Gas / Union Gas, currently operating as Enbridge Gas] service?

KEY SATISFACTION METRICS: RESIDENTIAL CUSTOMERS

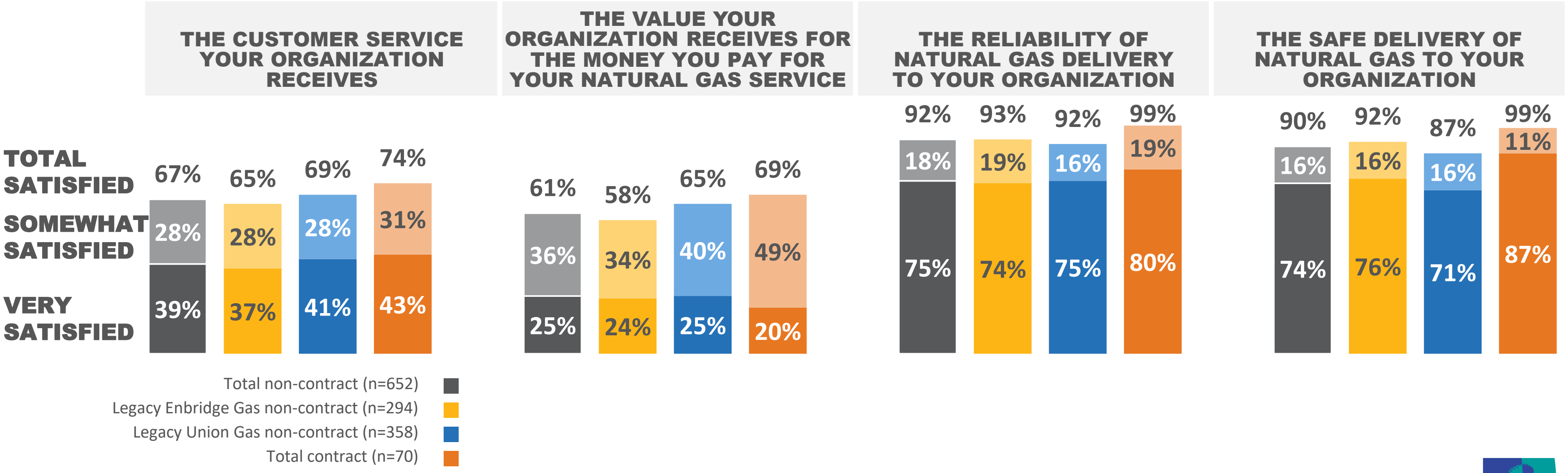
Virtually all residential customers are **satisfied** with the safety (95%) & reliability (98%) of natural gas delivery to their home, of which at least eight in ten (or more) are ***very satisfied***. A majority of customers are also **satisfied** with the customer service (75%) and value they are receiving for their money (78%). Legacy Union Gas residential customers are more likely (at 81%) to express satisfaction with the value they receive, compared to their legacy Enbridge Gas counterparts (74%).



Q3. How would you rate [Enbridge Gas / Union Gas, currently operating as Enbridge Gas] when it comes to each of the following?

KEY SATISFACTION METRICS: BUSINESS CUSTOMERS

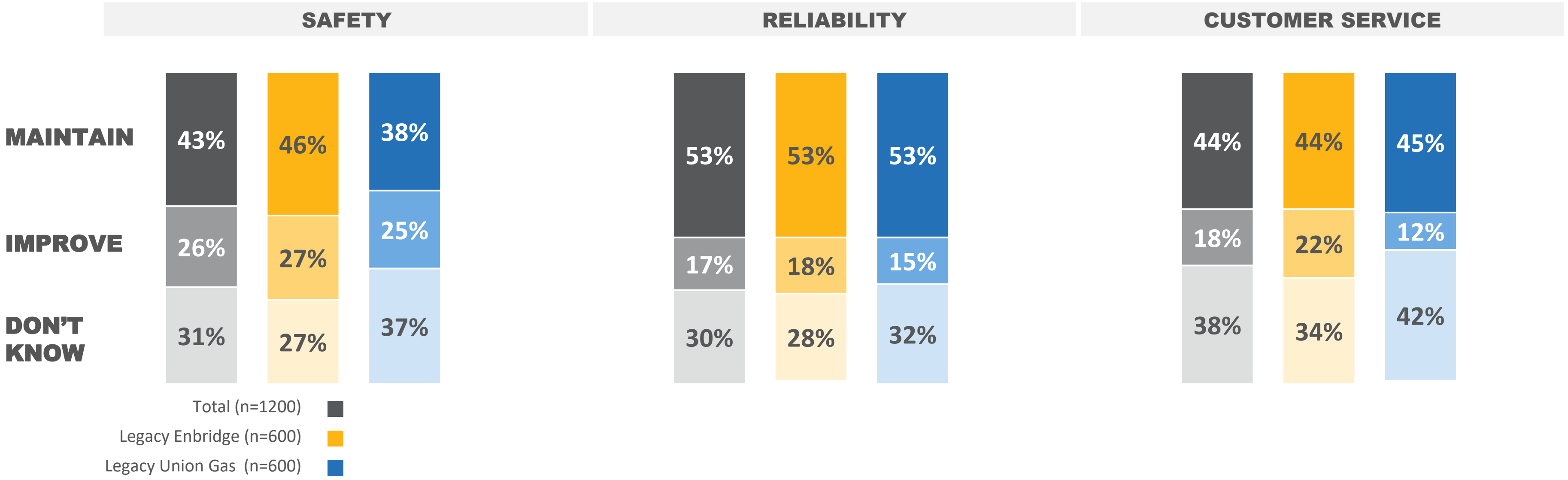
Nine in ten non-contract business customers are **satisfied** with the safety (90%) & reliability (92%) of the natural gas services they receive. Two-thirds (67%) of non-contract businesses are satisfied with customer service, while three in five (61%) feel this way about the value for money paid. Across all metrics, satisfaction levels tend to be higher among contract business customers.



Q3. How would you rate [Enbridge Gas / Union Gas, currently operating as Enbridge Gas] when it comes to each of the following?

INVESTMENT PRIORITIES: RESIDENTIAL CUSTOMERS

Across all metrics, the highest proportion of residential customers would like to see Enbridge Gas Inc. invest in ***maintaining*** current levels of safety, reliability, and customer service. Legacy Enbridge Gas residential customers are more likely (at 22%) than their legacy Union Gas counterparts (12%) to think that Enbridge Gas Inc. should focus on improving customer service.



Q4. Thinking about the level of safety, reliability and customer service you receive from [Enbridge Gas / Union Gas, currently operating as Enbridge Gas], would you like to see [Enbridge Gas / Union Gas, currently operating as Enbridge Gas] invest in maintaining or improving upon the current level? If you don't know please say so. How about …?

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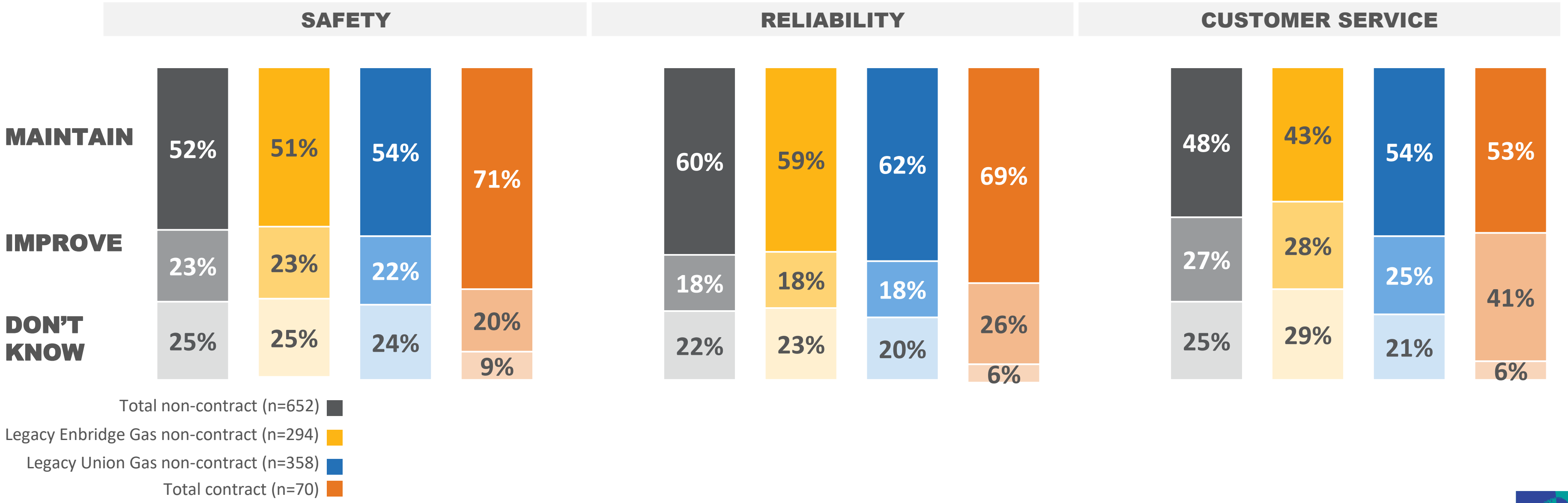
INVESTMENT PRIORITIES: BUSINESS CUSTOMERS

At least half of non-contract business customers and a majority of contract business customers would like Enbridge Gas Inc. to ***maintain*** current levels of safety (52% non-contract; 71% contract) and reliability (60% non-contract; 69% contract). Around half feel this way about customer service (48% non-contract; 53% contract).

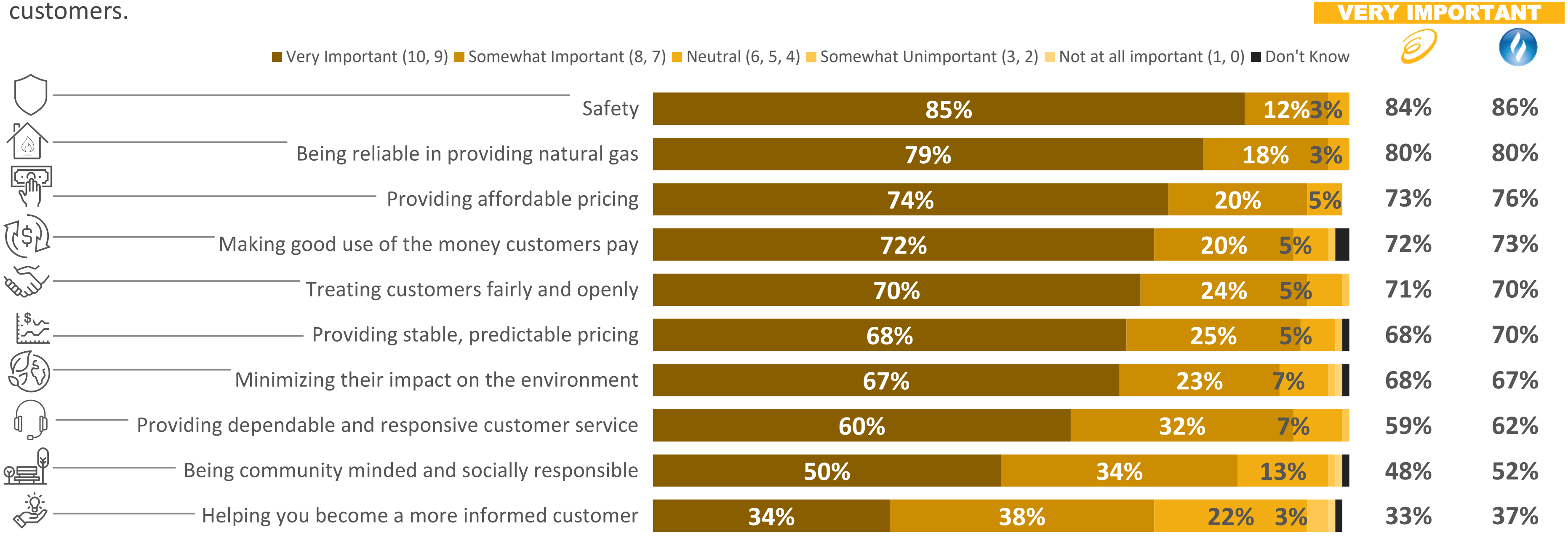


Q4. Thinking about the level of safety, reliability and customer service you receive from [Enbridge Gas / Union Gas, currently operating as Enbridge Gas], would you like to see the company invest in maintaining or invest in improving upon the current level? If you don't know please say so. How about ...?


CUSTOMER
OUTCOMES

CUSTOMER OUTCOMES: RESIDENTIAL CUSTOMERS

Safety (85% ‘*very important*’) & reliability (79%) top the list as the most highly rated customer outcomes among residential customers. Aside from informing customers (34%), being community minded & socially responsible (50%), majorities of customers view all other types of customer outcomes as being *very important*. Ratings are consistent across both legacy Union Gas & Enbridge Gas Distribution customers.

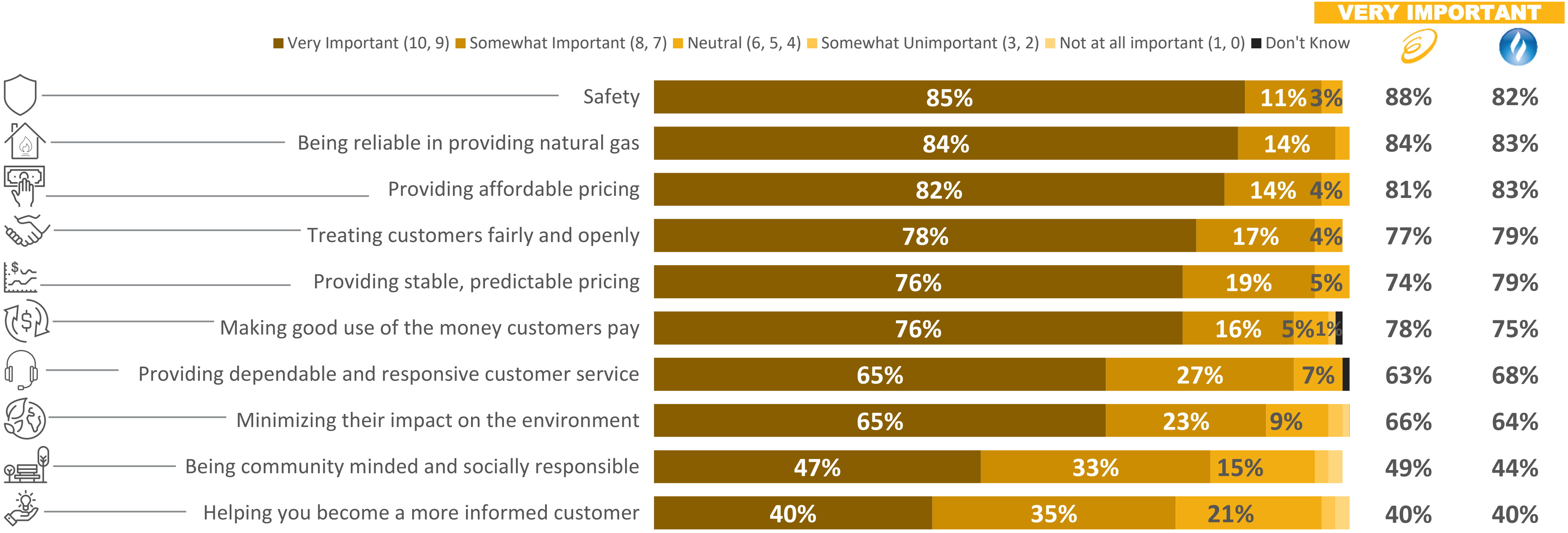


Q5. I am going to read you a list of customer outcomes that planners need to consider, and I’d like you to tell me how important each of them is to you. Please answer using a scale from 0 to 10, where 0 means “not at all important” and 10 means “extremely important”. I will read the entire list through once, and then we will go through the list one at a time. Be sure to save a rating of 10 for those items that are most important to you. How about …?
Base: Total residential customers (n=1200); legacy Enbridge Gas (n=600); legacy Union Gas (n=600)

*Data less than 3% not shown

CUSTOMER OUTCOMES: NON-CONTRACT BUSINESS

The vast majority of non-contract business customers rate safety (85%), reliability (84%), and affordability (82%) as being ***very important*** customer outcomes. Nearly nine in ten (88%) Legacy Enbridge Gas non-contract business customers rate safety as being highly important, a statistically higher proportion relative to their Legacy Union Gas counterparts (82%).

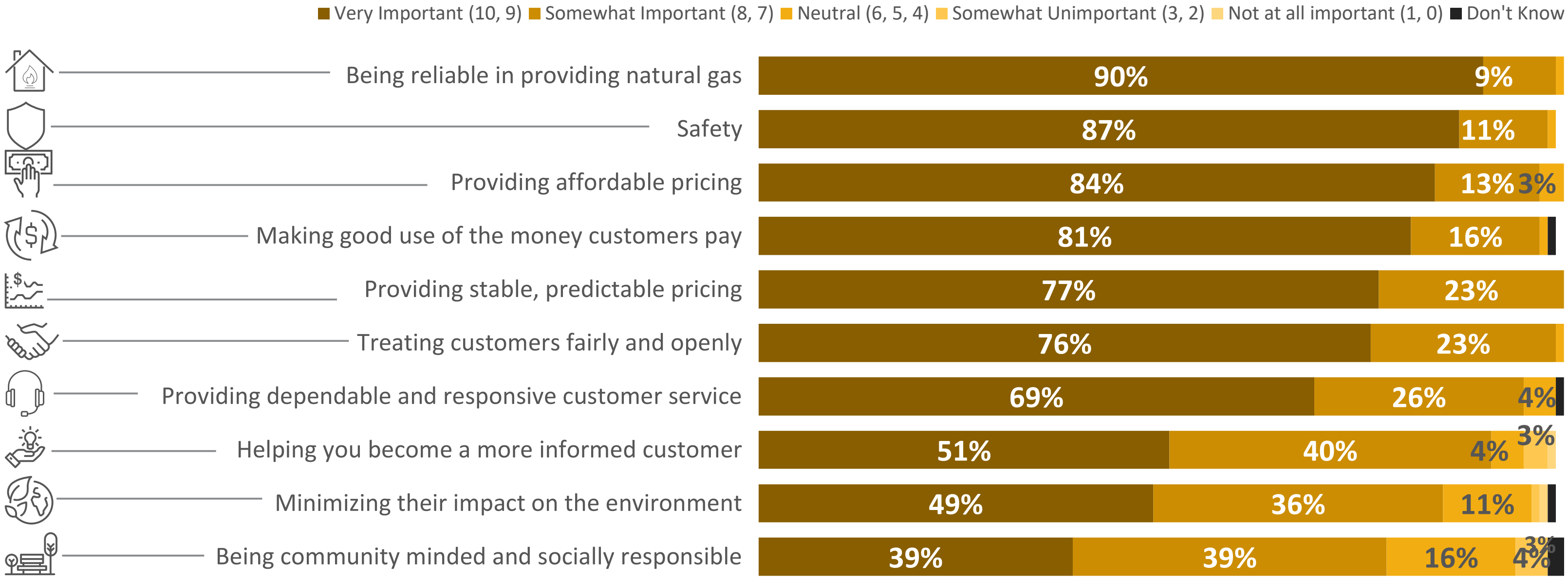


Q5. I am going to read you a list of customer outcomes that planners need to consider, and I'd like you to tell me how important each of them is to you. Please answer using a scale from 0 to 10, where 0 means "not at all important" and 10 means "extremely important". I will read the entire list through once, and then we will go through the list one at a time. Be sure to save a rating of 10 for those items that are most important to you. How about …?
Base: Total non-contract business customers (n=652); legacy Enbridge Gas (n=294); legacy Union Gas (n=358)

*Data less than 3% not shown

CUSTOMER OUTCOMES: CONTRACT BUSINESS CUSTOMERS

Reliability (90% '*very important*') tops the list as the most highly rated customer outcome, followed closely by safety (87%) and affordability (84%), among contract business customers.

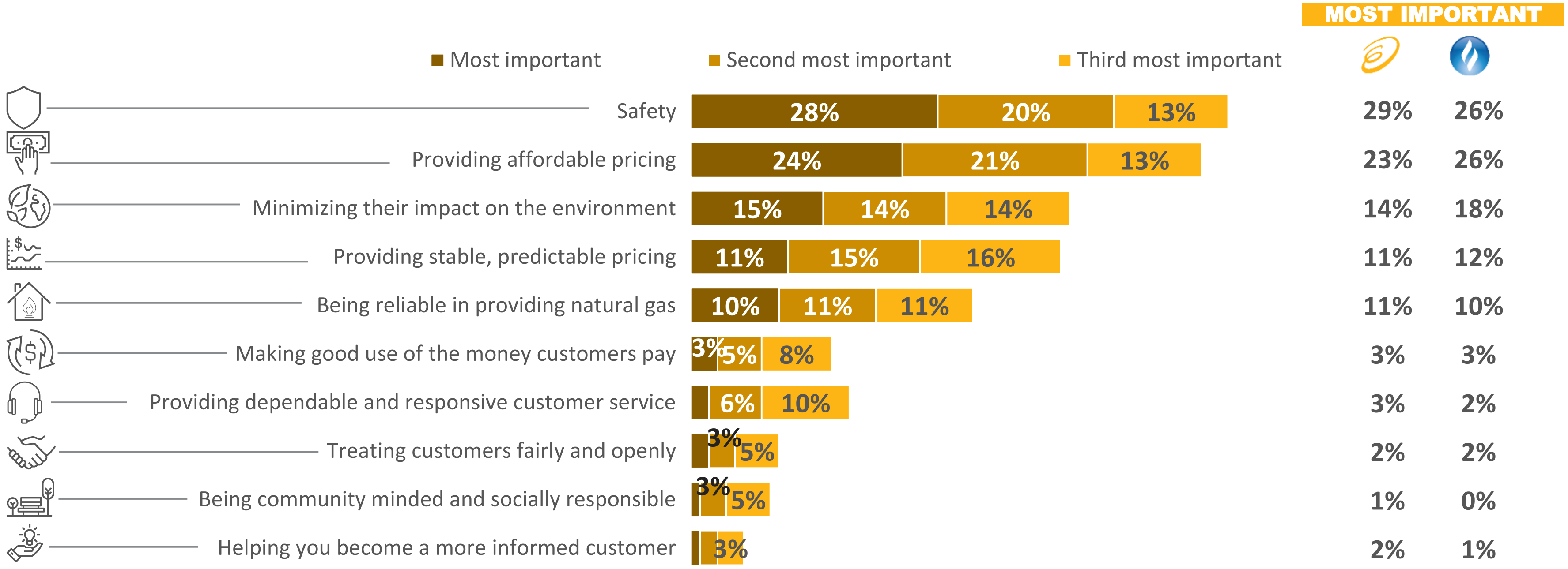


Q5. I am going to read you a list of customer outcomes that planners need to consider, and I'd like you to tell me how important each of them is to you. Please answer using a scale from 0 to 10, where 0 means "not at all important" and 10 means "extremely important". I will read the entire list through once, and then we will go through the list one at a time. Be sure to save a rating of 10 for those items that are most important to you. How about ...?
Base: Total respondents (n=70)

*Data less than 3% not shown

CUSTOMER PRIORITIES: RESIDENTIAL CUSTOMERS

Nearly three in ten (28%) residential customers rate safety as being the ***most important*** customer priority, followed closely by one in four (24%) who feel this way about affordability. Fifteen percent (15%) view environmental impact as most important.

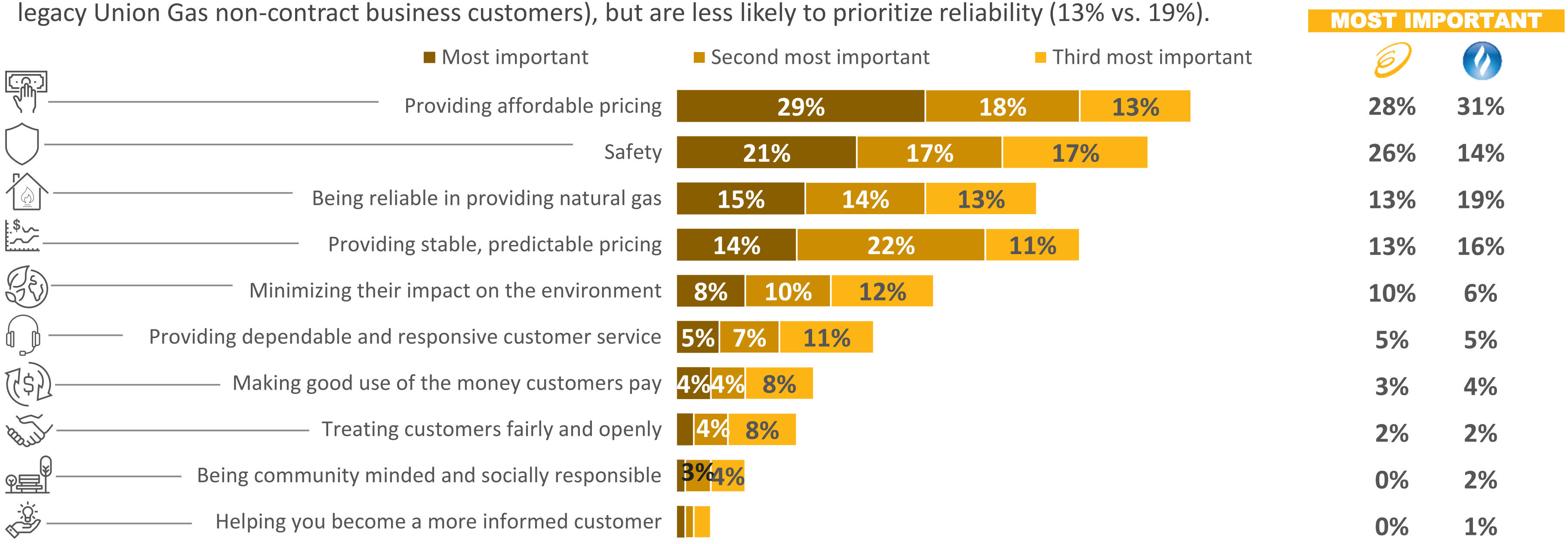


Q4a. Sometimes we need to choose between priorities that are all ranked quite highly. Thinking about these outcomes, which one would you say is most important to you as a customer? Q4b. And which is second most important to you? Q4c. And, finally, which one is third most important to you?
Base: Total residential customers (n=1200); legacy Enbridge Gas (n=600); legacy Union Gas (n=600)

**Data less than 3% not shown*

CUSTOMER PRIORITIES: NON-CONTRACT BUSINESS

Three in ten (29%) non-contract business customers rate affordability as the ***most important*** customer priority. One in five (21%) believe safety is most important, fifteen percent (15%) cite reliability, and fourteen percent (14%) rank providing stable, predictable pricing as most important. Legacy Enbridge Gas non-contract business customers are twice as likely to rate safety as most important (26% vs. 14% legacy Union Gas non-contract business customers), but are less likely to prioritize reliability (13% vs. 19%).



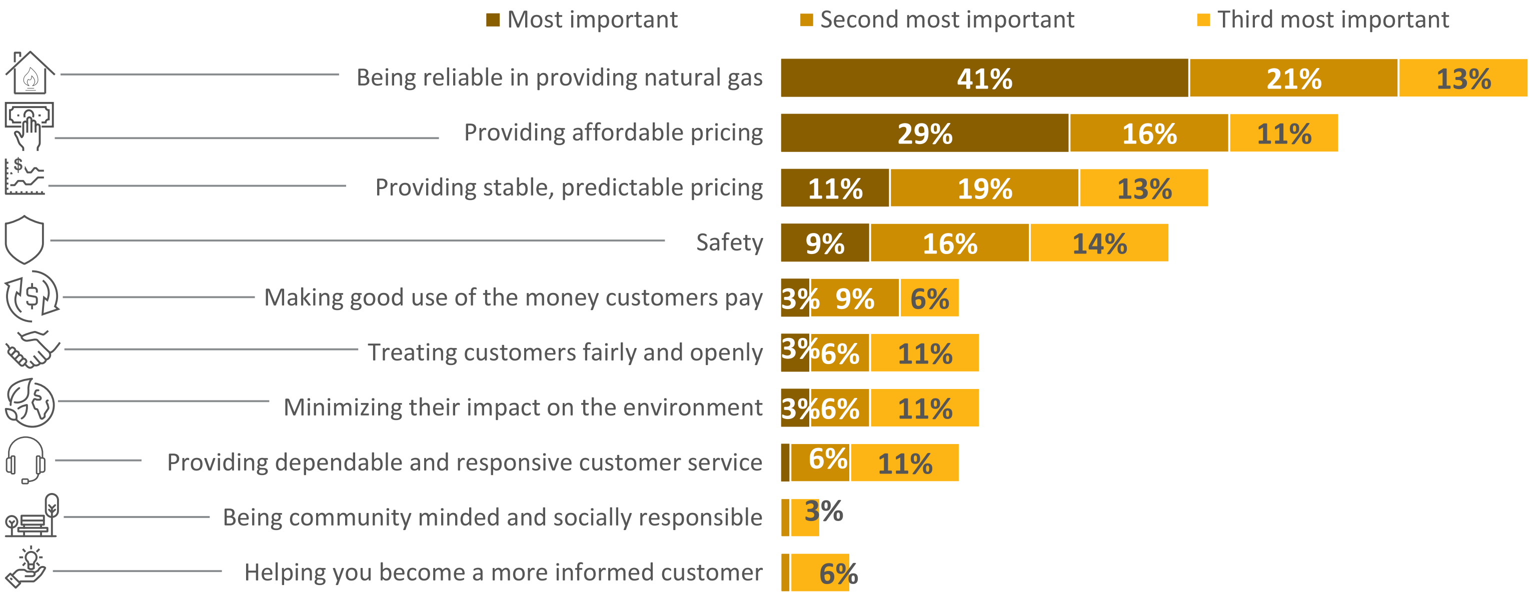
Q4a. Sometimes we need to choose between priorities that are all ranked quite highly. Thinking about these outcomes, which one would you say is most important to your organization? Q4b. And which is second most important to you? Q4c. And, finally, which one is third most important to you?
Base: Total non-contract business (n=652); legacy Enbridge Gas (n=294); legacy Union Gas (n=358)

Data less than 3% not shown

CUSTOMER PRIORITIES: CONTRACT BUSINESS CUSTOMERS

ENBRIDGE

Four in ten (41%) contract business customers choose reliability as the ***most important*** customer priority, followed three in ten (29%) who rank affordability first and one in ten customers who rank stable and predictable pricing (11%) or safety (9%) first.



Q4a. Sometimes we need to choose between priorities that are all ranked quite highly. Thinking about these outcomes, which one would you say is most important to your organization? Q4b. And which is second most important to you? Q4c. And, finally, which one is third most important to you?
Base: Total contract business (n=70)

**Data less than 3% not shown*

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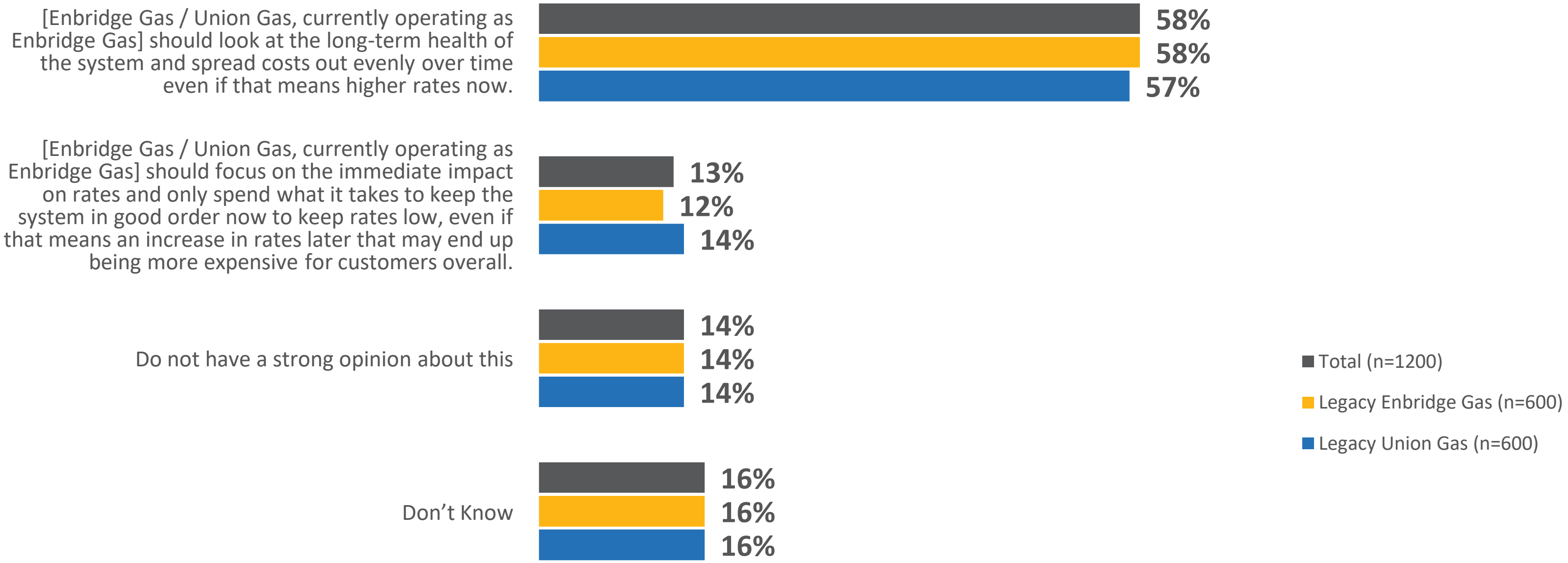
INVESTMENTS

REPLACING PIPELINES & EQUIPMENT: RESIDENTIAL

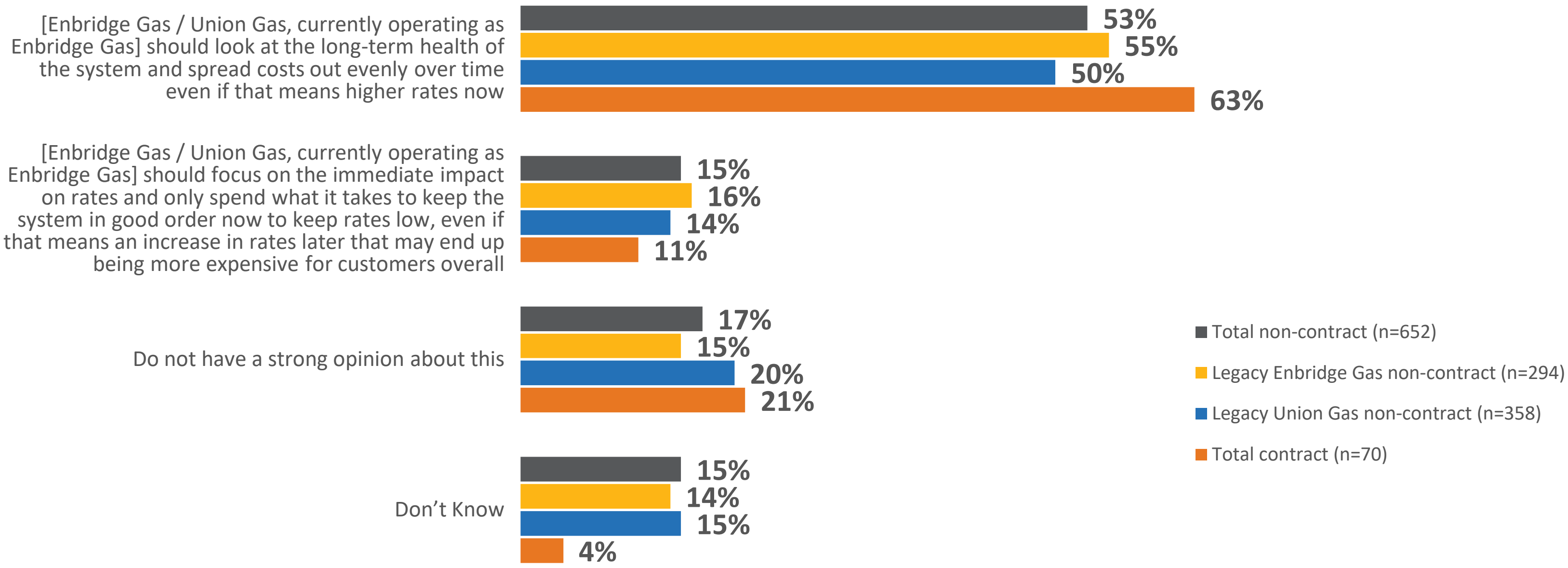
Well over half (58%) of residential customers believe that the best approach to replacing pipelines & equipment would be to ***spread costs evenly over time even if it means higher rates now***. Only about one in seven (13%) residential customers would prefer that rates are kept low and spend only what is necessary on repair, even if that means a potential increase in rates later. A similar proportion of customers 'do not have a strong opinion about this' (14%) or 'don't know' (16%).



Q6. Thinking generally about [Enbridge Gas / Union Gas, currently operating as Enbridge Gas] budget for replacing pipelines and equipment that deliver gas to your home, which of the following statements best represents your point of view?

REPLACING PIPELINES & EQUIPMENT: BUSINESS

About half (53%) of non-contract business customers believe that their natural gas provider should ***spread pipeline replacement costs over time.*** Two-thirds (63%) of contract business customers indicate the same. A minority of business customers would prefer that rates are kept low and spend only what is necessary on repair, even if that means a potential increase in rates later. Similar proportions of business customers either 'do not have a strong opinion about this' or 'don't know'.



Q6. Thinking generally about [Enbridge Gas / Union Gas, currently operating as Enbridge Gas] budget for replacing pipelines and equipment that deliver gas to your organization, which of the following statements best represents your organization's point of view?

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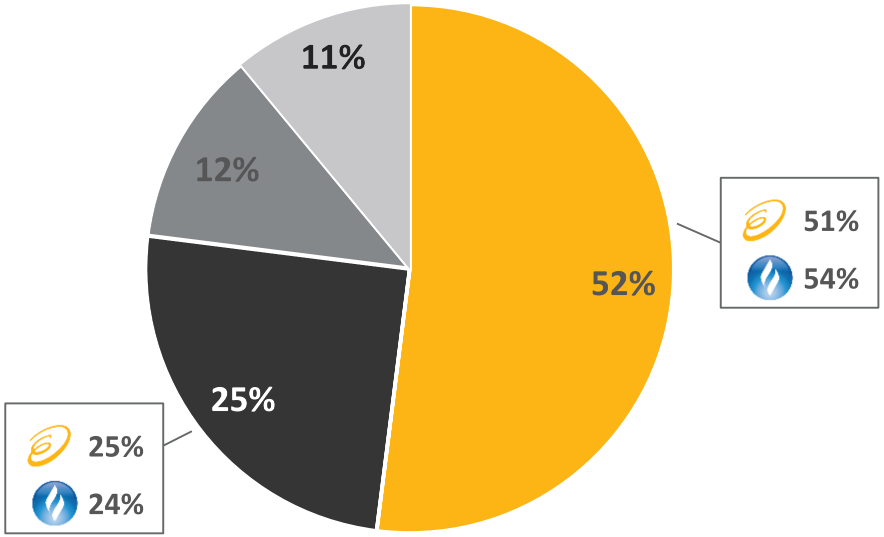
REPLACING OLDER PIPELINES: RESIDENTIAL CUSTOMERS

Residential customers are about twice as likely to say they would rather ***replace older pipes all at one time*** (52%) as opposed to in phases (25%), when asked to select their preferred method of pipeline replacement.

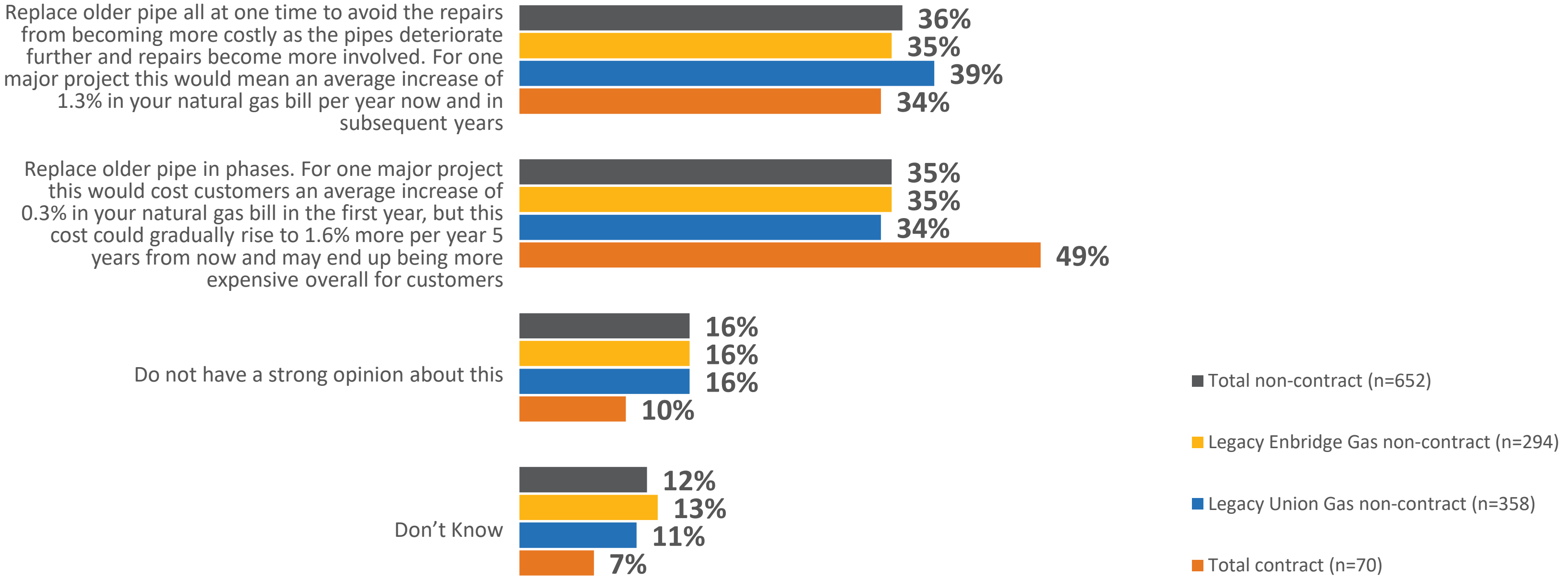
- Replace older pipe all at one time to avoid the repairs from becoming more costly as the pipes deteriorate further and repairs become more involved. For one major project this would cost customers $3 a year more than they are paying now in the first and subsequent years
- Replace older pipe in phases. For one major project this would cost customers only $0.50 a year more in the first year than they are paying now, but this cost could gradually rise to $3.50 more per year 5 years from now and may end up being more expensive overall for customers.
- Don’t have a strong opinion
- Don’t Know



Q7. The natural gas pipeline network in Ontario has been built over the course of the last 90 years. Through the course of general maintenance, older pipe that is degraded or damaged is repaired or replaced for newer pipe. Older pipe is more susceptible to failure and leaks because of vintage materials, corrosion and broken fittings like valves. Which of the following most closely reflects how you would like to see this investment made? I will provide costs for one major project as an example.
Base: Total respondents (n=1200); legacy Enbridge Gas (n=600); legacy Union Gas (n=600)

REPLACING OLDER PIPELINES: BUSINESS CUSTOMERS

Non-contract business customers are evenly split in their opinion about replacing older pipelines, with one in three (36%) favouring replacing older pipe all at one time and the same proportion of customers (35%) preferring to have this done in phases. Contract business customers are more likely to prefer the replacement in phases, with half (49%) of these customers supporting this approach.

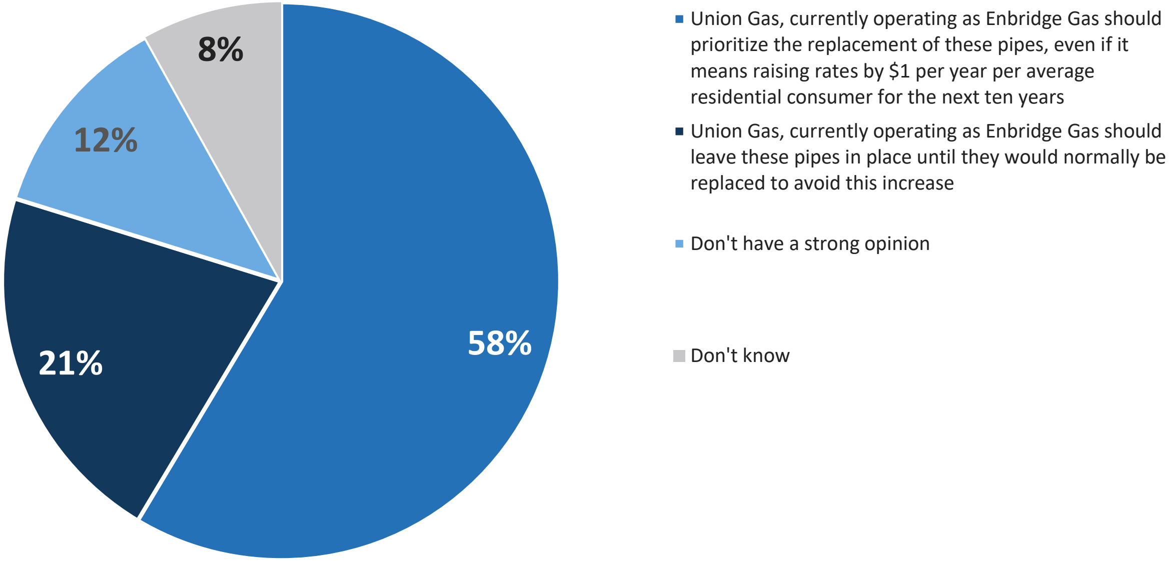


Q7. The natural gas pipeline network in Ontario has been built over the course of the last 90 years. Through the course of general maintenance, older pipe that is degraded or damaged is repaired or replaced for newer pipe. Older pipe is more susceptible to failure and leaks because of vintage materials, corrosion and broken fittings like valves. Which of the following most closely reflects how you would like to see this investment made on behalf of your organization? I will provide costs for one major project as an example.

BARE & UNPROTECTED PIPES: RESIDENTIAL CUSTOMERS

Legacy Union Gas residential customers are nearly three times more likely (at 58%) to say they think their natural gas provider should ***prioritize replacing old pipes*** even if it means raising rates by $1 per year for the next decade, instead of leaving the pipes in place until they would normally be replaced to avoid an increase in rates (21%).

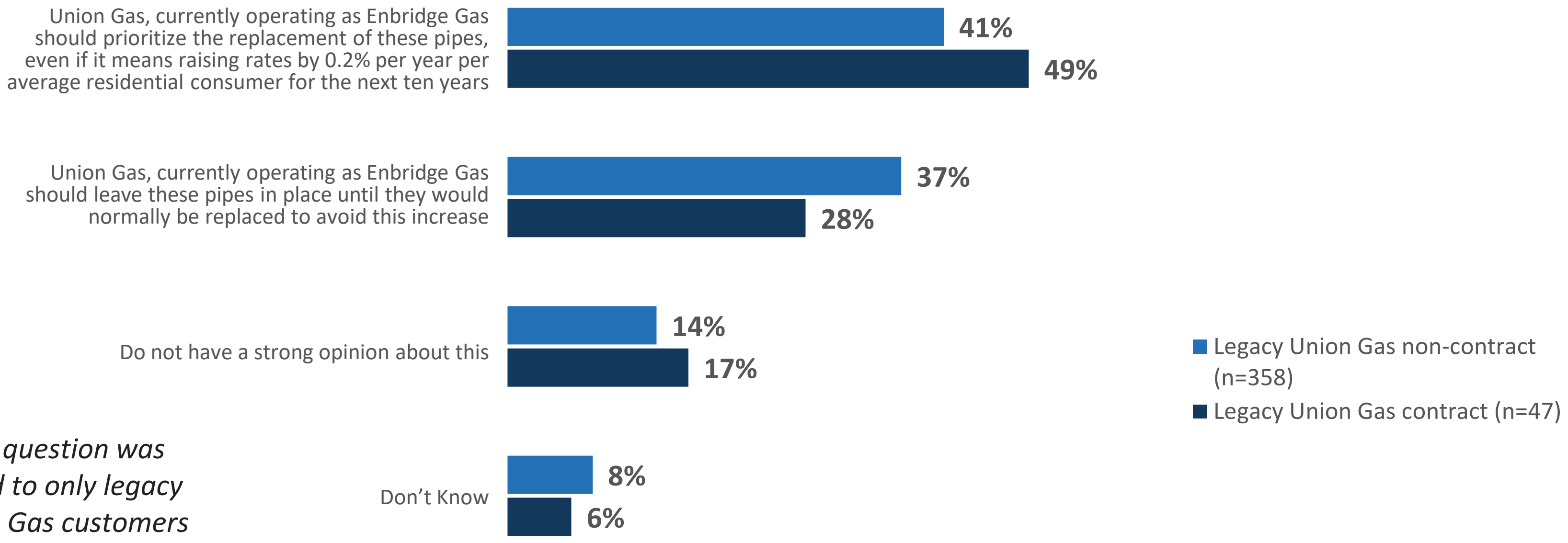
The question was asked to only legacy Union Gas customers



Q8. Today's installation procedures require that all new steel pipelines that are installed are coated and have cathodic protection in place to help prevent leaks and avoid corrosion. The company has some older pipes still in use that are not coated nor protected in this way. Under older rules and regulations these pipes were not required to be coated and protected, however they are more susceptible to corrosion and leaks. The cost to replace these pipes would be over and above the budget set aside for regular ongoing monitoring and inspection and repairs of any leaks found. Replacing all bare and unprotected pipe in the Legacy Union Gas system would increase rates by $1 per year for 10 years. Thinking about the issue of bare and unprotected pipes, which of the following most closely reflects your view?
Base: Total Union Gas respondents (n=600)

BARE & UNPROTECTED PIPES: UNION GAS BUSINESS

Legacy Union Gas non-contract customers are split in their preference for either prioritizing the replacement of unprotected pipes with an increase in rates (41%) or leaving these pipes in place until they would normally be replaced and avoid any increase in rates (37%). Legacy Union Gas contract customers are more likely to prefer the prioritization of unprotected pipes (49%), compared to replacing these pipes until they would normally be replaced (28%).



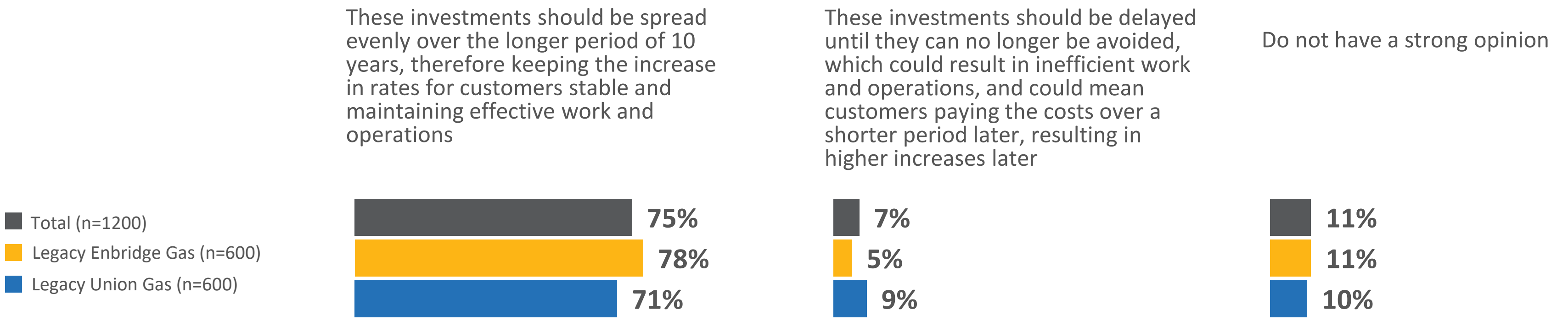
The question was asked to only legacy Union Gas customers

Q8. Today's installation procedures require that all new steel pipelines that are installed are coated and have cathodic protection in place to help prevent leaks and avoid corrosion. The company has some older pipes still in use that are not coated nor protected in this way. Under older rules and regulations these pipes were not required to be coated and protected, however they are more susceptible to corrosion and leaks. The cost to replace these pipes would be over and above the budget set aside for regular ongoing monitoring and inspection and repairs of any leaks found. Replacing all bare and unprotected pipe in the Legacy Union Gas system would increase rates by 0.2% per year for 10 years. Thinking about the issue of bare and unprotected pipes, which of the following most closely reflects your organization's point of view?

SPENDING ON BUILDING & EQUIPMENT

MAINTENANCE OPERATIONS: RESIDENTIAL CUSTOMERS

Three-quarters (75%) of residential customers favour **spreading investments in maintenance operations evenly over a 10-year period**. Few (7%) customers support delaying investments. Legacy Enbridge Gas residential customers are statistically more likely to favour spreading investments across a longer period of time (at 78%) than legacy Union Gas residential customers (71%).



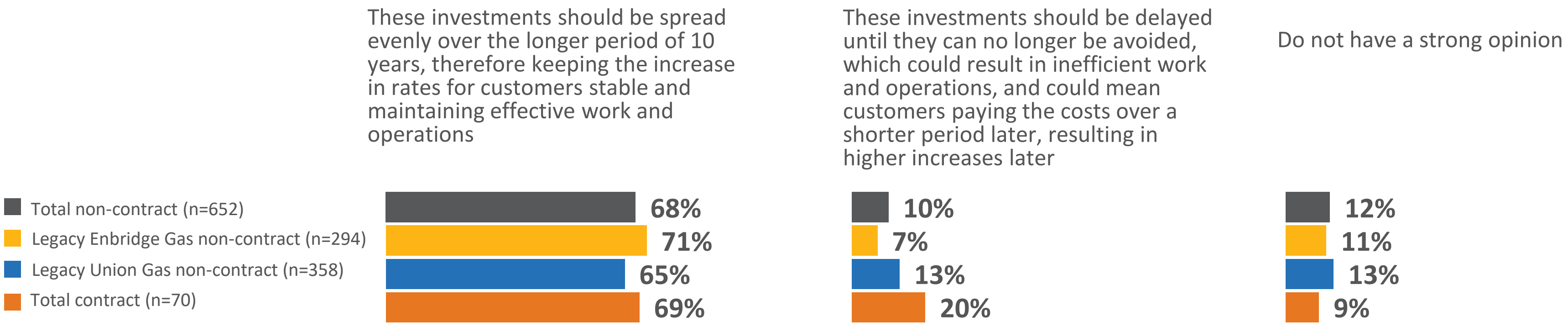
DON'T KNOW: 7%, 6%, 9%

REFUSAL: 1%, 1%, >0%

Q9. [Enbridge Gas / Union Gas, currently operating as Enbridge Gas] needs to plan for making long-term investments to renovate its older buildings and build new ones that support efficient work and operations in its offices and maintenance yards. The cost of these investments is planned evenly at an average cost of 50 cents per year on each customer's bill for the next 10 years. Another option is to hold-off making any investment in buildings for several years and risk a larger increase to customer bills over a shorter period down the road when the renovations and construction are unavoidable. Which of the following statements comes closest to your point of view?

MAINTENANCE OPERATIONS: BUSINESS CUSTOMERS

More than two-thirds of non-contract (68%) and contract (69%) business customers favour **spreading investments in maintenance operations evenly over a ten year period**. One in five (20%) contract business customers think they should be delayed and one in ten (10%) non-contract business customers feel this way. Legacy Union Gas non-contract business customers are more likely to support delaying these investments than their legacy Enbridge Gas counterparts (13% vs. 7%).

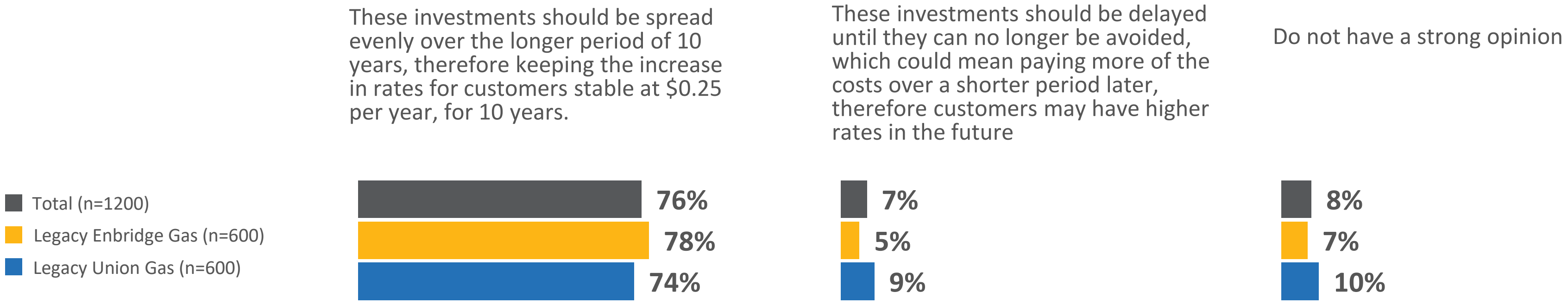


DON'T KNOW: 9%, 10%, 8%, 3%

Q9. [Enbridge Gas / Union Gas, currently operating as Enbridge Gas] needs to plan for making long-term investments to renovate its older buildings and build new ones that support efficient work and operations in its offices and maintenance yards. The cost of these investments is planned evenly at an average increase of 0.2% per year on your natural gas bill for the next 10 years. Another option is to hold-off making any investment in buildings for several years and risk a larger increase to customer bills over a shorter period down the road when the renovations and construction are unavoidable. Which of the following statements comes closest to your organization's point of view?

FLEET UPGRADE & MAINTENANCE: RESIDENTIAL

A strong majority (76%) of residential customers support **spreading long-term investments to maintain and improve its fleet and equipment evenly over a ten year period**. Few (7%) residential customers think investments in fleet upgrade & maintenance should be delayed, though legacy Union Gas customers are more likely (at 9%) to think this should be delayed than their legacy Enbridge Gas counterparts (5%).



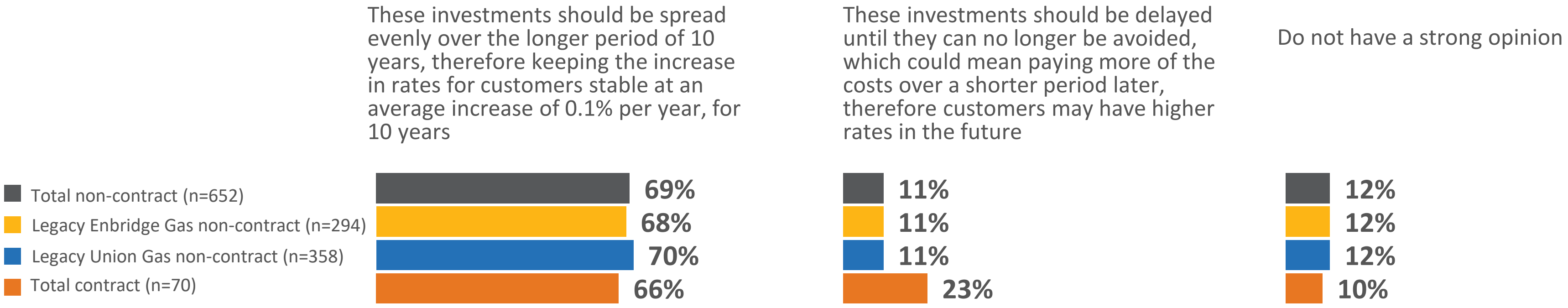
DON'T KNOW: 8%, 9%, 7%

REFUSAL: 1%, 1%, >0%

Q10. [Enbridge Gas / Union Gas, currently operating as Enbridge Gas] needs to plan for making long-term investments to maintain and improve its fleet for the safety of our employees as well as efficiency and cost effectiveness of operations. The fleet includes the light and medium duty vehicles used by employees, as well as some heavy equipment and tools. The cost of these investments is planned evenly at an average cost of 25 cents per year on each customer's bill for the next 10 years. Another option is to hold-off making any investment for several years and a larger increase to customer bills over a shorter period down the road when maintenance and upgrades are unavoidable. Which of the following statements comes closest to your point of view?

FLEET UPGRADE & MAINTENANCE: BUSINESS CUSTOMERS

Strong majorities of non-contract (69%) and contract (66%) business customers support **spreading investments in fleet and equipment over a longer period of ten years**. Only about one in ten non-contract business customers prefer to delay these investments, however almost one-quarter of contract business customers would prefer this approach.



DON'T KNOW: 8%, 8%, 7%, 1%

Q10. [Enbridge Gas / Union Gas, currently operating as Enbridge Gas] needs to plan for making long-term investments to maintain and improve its fleet for the safety of its employees as well as efficiency and cost effectiveness of operations. The fleet includes the light and medium duty vehicles used by employees, as well as some heavy equipment and tools. The cost of these investments is planned evenly at an average increase of 0.1% per year on your natural gas bill for the next 10 years. Another option is to hold-off making any investment for several years and risk a larger increase to customer bills over a shorter period down the road when maintenance and upgrades are unavoidable. Which of the following statements comes closest to your point of view?

ADDITIONAL CUSTOMER FEEDBACK

IN THEIR OWN WORDS: RESIDENTIAL

“I feel like any business have a margin profit and they should invest it instead of asking customers to pay for more."

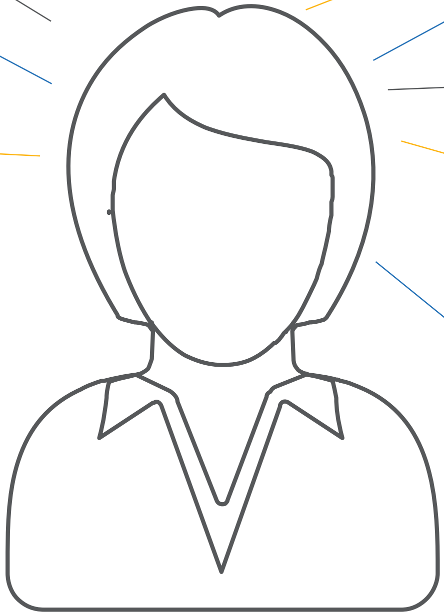
“I'm very happy, we've never had a problem, keep it up, I only ever spoke with them once almost 10 years ago and the service has been flawless ever since, It is one of the only bills that hasn't doubled or tripled.”

“For what I pay per month I don't feel my value is received, I pay more in administration fees and delivery charges than actual gas and use, it's outrageous how much you pay in administration fees for what you use. I don't feel I'm getting a good value."

“I'm quite happy with Enbridge. They're excellent.”

“CEOs are making too much money and they're spending it on a lot of useless things. Basically, we are top heavy. Yeah, it's great to charge the guy using it, but the guy who's at the top, has to stop being greedy.”

“I think we need alternative modes of fuel/energy to become more green. We need to realize making theses changes will affect our pocket books. When you are using tax payer money, it is easy to not look at the cost of things, but we need to.”



“Union Gas has done a really good job of providing heating for our home. We don't mind increasing the cost as long as that infrastructure and the safety of the employees is looked after. I think it is up to the consumers to replace the windows and maybe they could support the Nest thermostats.”

“They should make all the necessary improvements for the safety of their customers.”

“Pipelines are the smartest way to do things, the reason to upgrade the network is because it is very expensive when it fails. It is a gas pipeline so if it fails all sorts of problems happen, especially in remote areas. Conservation is a good thing, I have upgraded my water heater, There are savings there so that is a good thing.”

“You guys are doing a good job and I'm sure we need some updated pipes especially in the older areas and these are all important.”

“I'm happy with the service. The whole house is on gas, and I have no complaints. My bills are decent.”

“So many issues with non-pipeline delivery seem not feasible for Union Gas / Enbridge.”

Q13. Do you have any comments you would like to share with [Enbridge Gas / Union Gas, currently operating as Enbridge Gas]?
Base: Total residential customers (n=1,200); legacy Enbridge Gas (n=600); legacy Union Gas (n=600)

OTHER COMMENTS: RESIDENTIAL

ENBRIDGE

	Total (n=1200)	Legacy Enbridge Gas (n=600)	Legacy Union Gas (n=600)
Positive (NET)	19%	18%	20%
It is good/ like it/ no problems	12%	12%	14%
Good service/ prompt service	5%	5%	5%
Price is good/ competitive	3%	2%	4%
Negative (NET)	17%	19%	15%
Lower price/ do not increase the bill	9%	10%	8%
They make too much profit	3%	2%	3%
Should not have to pay more for service for them to upgrade their infrastructure	3%	4%	2%
Need to think more about conservation/ sustainability/ concerned about environment	4%	5%	2%
Concerned about safety/ need to focus on safety	3%	3%	3%
Should look at alternative delivery methods/ need to move to alternative energy sources (wind, solar, alternatives to carbon-based energy)	3%	3%	3%
Other	8%	8%	8%
None	37%	35%	38%
Don't know / refusal	17%	18%	16%

Q13. Do you have any comments you would like to share with [Enbridge Gas / Union Gas, currently operating as Enbridge Gas]?

*Mentions less than 3% not shown

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IN THEIR OWN WORDS: NON-CONTRACT BUSINESS

“I am always amazed that a survey needs to be done to help decide the future of a company and how much of an increase is viable. Replacing infrastructure should have been included in pricing long before NOW.”

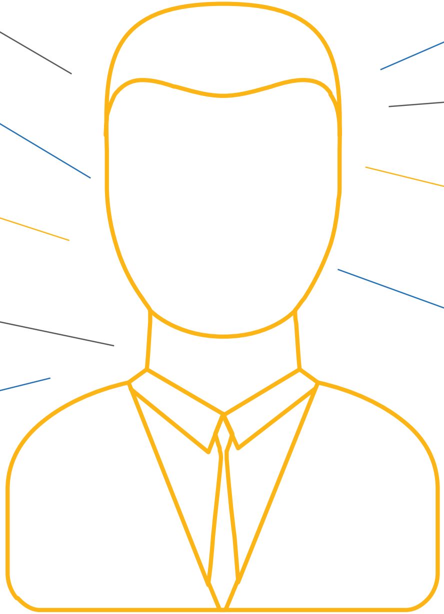
“The environmental impact should be top of mind in any decisions being made!"

“Would like to see the company who is profiting pay for the repairs to the pipelines and not the customers. You make the money its your business you should soak the cost as you will get it back. Unfair to charge customers.”

“Service is good. I get my gas. No complaints.”

“The cost of energy is getting to the point where we will close locations rather than take the increases due to carbon taxes and time of use billing.”

“I like the forward thinking. This is really good.“



“Union Gas, as an energy provider, has in the past been a safe and stable company. We hope this continues with Enbridge.”

“I don't have very good comments for them. I do the finances where I work. We can't Increase our prices to our customers for upgrades to our buildings and vehicles.”

“Enbridge is one operation I've never questioned, they seem to be very good, I admire them, they're a good company.”

“Not really, we have a good gas supply, everything works fine. If we could have someone come out and discuss energy saving with us, that would be good.”

“They need to transition off of fossil fuels. I'm building a house and I'm not rich, but I'm putting anything in it that is not involved with fossil fuels.”

Q13. Do you have any comments you would like to share with [Enbridge Gas / Union Gas, currently operating as Enbridge Gas]?
Base: Total non-contract business customers (n=652); legacy Enbridge Gas (n=294); legacy Union Gas (n=358)

IN THEIR OWN WORDS: CONTRACT BUSINESS

"Very happy with customer service. Challenge is keeping prices low for our business."

"Like any other well managed business, Enbridge should implement cuts to its operating expenses i.e. staff, premises, fleet of vehicles etc. etc. Also, incentive programs to businesses for curtailing gas use should be abolished as its in the interest of businesses to make those investments by themselves."

"The way pipelines are being installed appears to be very expensive. I know we have to be safety minded but everything looks like overkill."

"It is UG's business to distribute gas and you charge your customers for this. Therefore you should maintain the tools you need in order to be able to continue to provide this service that you are being paid for."

"Union should make an effort to fix the Unionline website where customers interact. It was the most user friendly website until the change (a year ago?)."

"Service is good. New installs are like pulling teeth."

"Good organization to work with."

"Infrastructure repairs need to be made to ensure a reliable gas supply. We have become very dependent on natural gas."

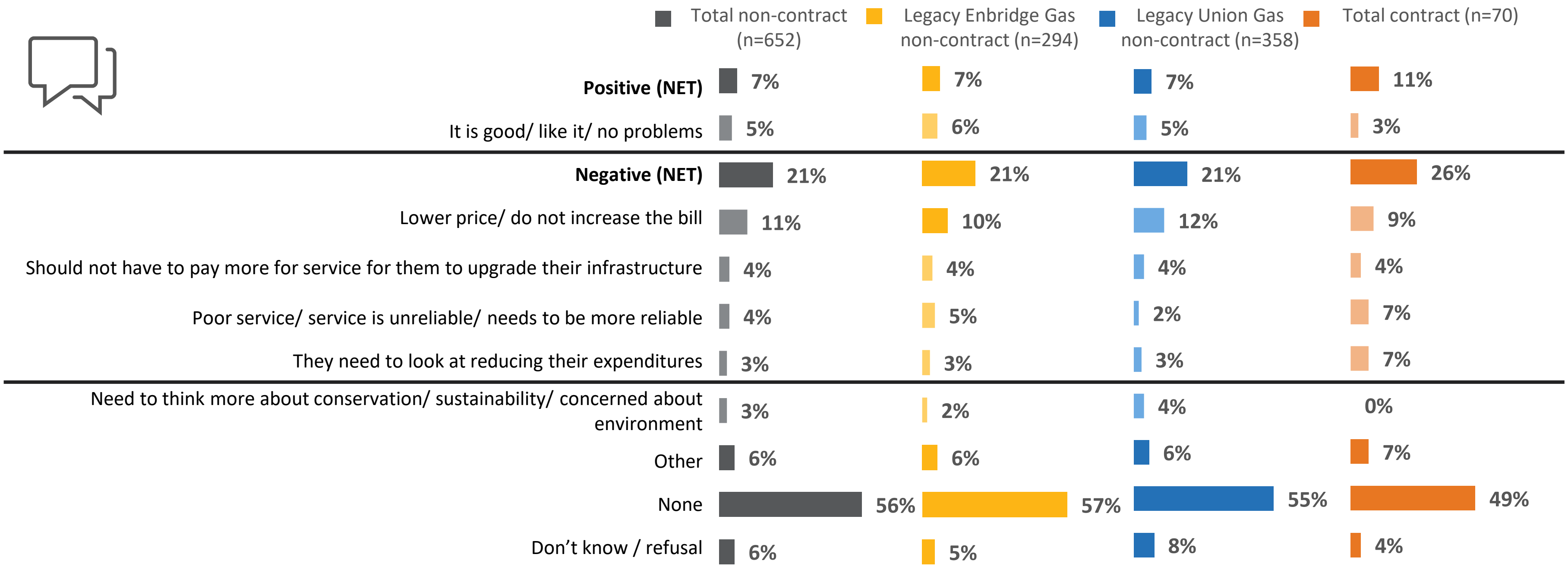
"Everyone replaces their roof in my neighbourhood.....no one is replacing windows. Too expensive for the payback. This appears obvious."

"Always enjoyed my interactions with everyone at Enbridge (Union) Gas."

"Union Gas operating as Enbridge should review reduction of the total quantity of their buildings & their fleet (vehicles) in order to reduce or avoid overall maintenance costs through consolidation & reduction of their corporate infrastructure."

Q13. Do you have any comments you would like to share with [Enbridge Gas / Union Gas, currently operating as Enbridge Gas]?
Base: Total contract business customers (n=70)

OTHER COMMENTS: BUSINESS



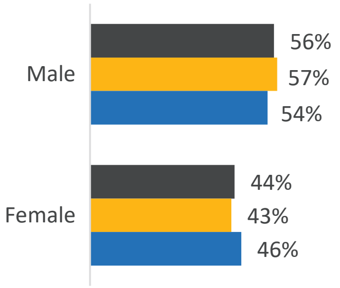
Q13. Do you have any comments you would like to share with [Enbridge Gas / Union Gas, currently operating as Enbridge Gas]?

*Mentions less than 3% not shown

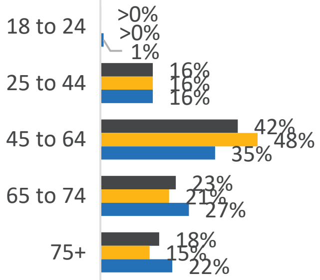
APPENDIX: PROFILE OF CUSTOMERS

PROFILE OF RESIDENTIAL CUSTOMERS

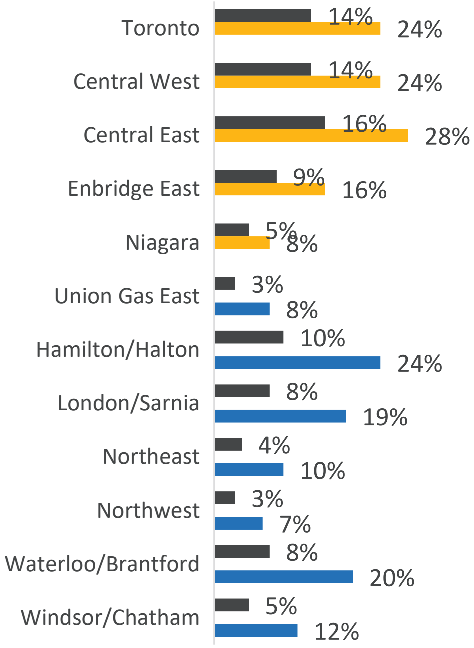
GENDER



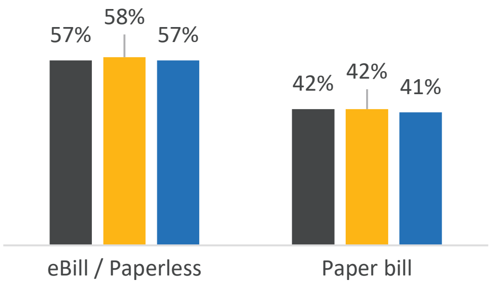
AGE



REGION

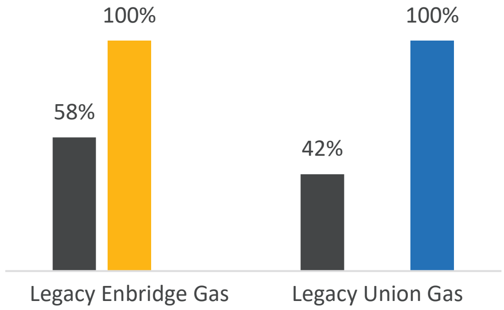


BILL TYPE



DON'T KNOW: 1%, 1%, 1%

CUSTOMER TYPE



Total (n=1200)
Legacy Enbridge Gas (n=600)
Legacy Union Gas (n=600)

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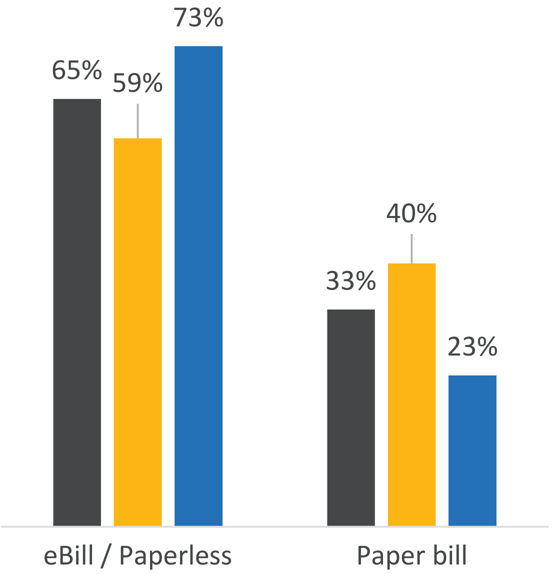
PROFILE OF NON-CONTRACT BUSINESS CUSTOMERS

BILL TYPE



DON'T KNOW: 2%, 1%, 3%

REGION