RATE BASE EVIDENCE AND SUMMARIES OVERVIEW
JASON VINAGRE, MANAGER REGULATORY ACCOUNTING

1. The purpose of this evidence is to summarize and request approval of Enbridge Gas's rate base and capital expenditures for the 2024 Test Year and to provide a description of the evidence supporting rate base as set out throughout Exhibit 2.

2. Rate base includes net property, plant and equipment, plus an allowance for working capital. Net property, plant and equipment (PPE), calculated on an average of monthly averages basis, equals gross PPE in-service minus accumulated depreciation minus any applicable contributions from customers. Allowance for working capital primarily consists of gas in storage, materials and supplies and a working cash allowance. The details of the 2024 Test Year components of rate base are provided later in this evidence.

3. Enbridge Gas is requesting the OEB to approve various requests, forecast methodologies and the various components supporting the 2024 Test Year rate base forecast, which are found in Exhibit 2 as set out below:

Exhibit 2, Tab 2, Schedule 1	Net Assets - Property Plant & Equipment
Exhibit 2, Tab 3, Schedule 1	Allowance for Working Capital
Exhibit 2, Tab 3, Schedule 2	Working Cash Allowance and Lead Lag Study
Exhibit 2, Tab 4, Schedule 1	Capitalization Policy Overview
Exhibit 2, Tab 4, Schedule 2	Capitalization of Overhead
Exhibit 2, Tab 5, Schedule 1	Capital Expenditures Overview
Exhibit 2, Tab 5, Schedule 2	Capital Expenditures
Exhibit 2, Tab 5, Schedule 3	Capital Expenditure History

4. As noted above rate base is comprised of two main components: net PPE and allowance for working capital, details of which are provided at Exhibit 2, Tab 2, Schedule 1 and Exhibit 2, Tab 3, Schedule 1, respectively. The evidence for net PPE provides details of the continuity and average of monthly average balances for functional plant assets, including in-service additions. Evidence for allowance for working capital provides details of the components of allowance for working capital on an average of monthly averages basis.

5. The working cash allowance component of allowance for working capital provided at Exhibit 2, Tab 3, Schedule 2, is supported by the Lead-Lag Study, which is provided at Exhibit 2, Tab 3, Schedule 2, Attachment 1.

6. In-service additions that form part of net PPE are supported by Enbridge Gas's capitalization policy and associated policy for capitalization of overheads which are provided at Exhibit 2, Tab 4, Schedule 1 and Exhibit 2, Tab 4, Schedule 2, respectively. In-service additions are informed by Enbridge Gas's capital expenditures on an actual and forecast basis. Exhibit 2, Tab 5, Schedule 1 provides an overview of Enbridge Gas's capital expenditures, Exhibit 2, Tab 5, Schedule 2 provides details of Enbridge Gas's 2024 Test Year capital expenditures budget, and Exhibit 2, Tab 5, Schedule 3 provides summaries of historical and forecast capital expenditures.

7. The Utility System Plan (USP) is provided at Exhibit 2, Tab 6, Schedule 1 and describes how the Company plans, strategizes, prioritizes and optimizes expenditures to produce investment plans that meet the needs of customers and the expectations set out in the OEB's Renewed Regulatory Framework (RRF). The USP supports Enbridge Gas's capital expenditures budget for forecast periods including the 2024 Test Year.

8. Table 1 provides a summary of the 2013 OEB-approved utility rate base and capital expenditures for EGD and Union and actual utility rate base and capital expenditures from 2013 to 2018 for EGD and Union. Table 2 provides actual utility rate base and capital expenditures from 2019 to 2021 and the 2022 Estimate, 2023 Bridge Year and 2024 Test Year Forecast of utility rate base and capital expenditures for Enbridge Gas. Utility rate base in the tables is presented on an average of monthly averages basis.

9. Year-over-year variances in utility rate base from 2019 to 2024 are provided at Attachment 1.

Table 1
Utility Rate Base & Capital Expenditures

Line No.	Particulars ($ millions)	Utility	2013 OEB-Approved	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Gross Property, Plant and Equipment	EGD	6,749.4	6,749.3	7,216.6	7,586.9	8,588.4	9,228.8	9,594.5
2	Accumulated Depreciation	EGD	(2,804.1)	(2,755.9)	(2,900.8)	(2,980.8)	(3,017.4)	(3,126.5)	(3,277.9)
3	Net Property, Plant and Equipment	EGD	3,945.3	3,993.4	4,315.8	4,606.1	5,571.0	6,102.3	6,316.6
4	Working Capital	EGD	216.7	299.8	385.5	473.7	338.0	362.9	412.6
5	Utility Rate Base	EGD	4,162.0	4,293.2	4,701.3	5,079.8	5,909.0	6,465.2	6,729.2
6	Capital Expenditures	EGD	449.9	517.8	612.3	1,015.4	593.9	431.4	413.3
7	Gross Property, Plant and Equipment	Union	6,361.5	6,401.2	6,674.3	7,029.5	7,683.0	8,628.2	9,398.6
8	Accumulated Depreciation	Union	(2,754.1)	(2,746.2)	(2,868.9)	(2,994.8)	(3,149.2)	(3,347.5)	(3,524.2)
9	Net Property, Plant and Equipment	Union	3,607.5	3,655.0	3,805.3	4,034.7	4,533.8	5,280.7	5,874.4
10	Working Capital	Union	196.8	198.2	225.8	235.5	254.1	210.5	148.5
11	Accumulated Deferred Income Taxes	Union	(69.7)	(69.3)	(54.7)	(41.8)	(29.5)	(17.3)	(4.5)
12	Utility Rate Base	Union	3,734.5	3,783.9	3,976.4	4,228.4	4,758.4	5,473.9	6,018.4
13	Capital Expenditures	Union	347.7	368.2	476.9	691.3	1,034.0	721.0	519.2
14	Total Utility Rate Base	Combined	7,896.5	8,077.1	8,677.7	9,308.2	10,667.4	11,939.1	12,747.6
15	Total Capital Expenditures	Combined	797.6	886.0	1,089.2	1,706.7	1,627.9	1,152.4	932.5

Table 2
Utility Rate Base & Capital Expenditures

Line No.	Particulars ($ millions)	Utility	2019 Actual (a)	2020 Actual (b)	2021 Actual (c)	2022 Estimate (d)	2023 Bridge Year (e)	2024 Test Year (f)	
1	Gross Property, Plant and Equipment	EGI	19,765.5	20,582.1	21,539.8	22,663.3	23,874.8	24,902.9	/u
2	Accumulated Depreciation	EGI	(7,188.7)	(7,571.2)	(8,005.9)	(8,417.8)	(8,924.1)	(9,178.9)	/u
3	Net Property, Plant and Equipment	EGI	12,576.8	13,010.8	13,533.9	14,245.4	14,950.7	15,724.0	/u
4	Allowance for Working Capital	EGI	562.3	551.2	687.7	855.9	689.4	557.0	/u
5	Utility Rate Base	EGI	13,139.0	13,562.0	14,221.6	15,101.3	15,640.1	16,281.1	/u
6	Capital Expenditures	EGI	1,087.4	1,007.4	1,310.8	1,444.3	1,605.7	1,491.3	/u

2024 Test Year Rate Base

10. For the 2024 Test Year, Enbridge Gas is requesting the OEB approve utility rate base of $16,281.1 million and capital expenditures of $1,491.3 million. Table 3 shows the utility rate base and its components for the 2024 Test Year on an average of monthly averages basis. /u

Table 3
Utility Rate Base Summary - Average of Monthly Averages

Line No.	Particulars ($ millions)	2024 Test Year (a)	
1	Gross Property, Plant and Equipment	24,902.9	/u
2	Accumulated Depreciation	(9,178.9)	/u
3	Net Property, Plant and Equipment	15,724.0	/u
4	Materials and Supplies	107.0	
5	Customer Security Deposits	(60.2)	
6	DCB Receivable (Payable)	(5.1)	
7	Gas in Storage	648.4	
8	Working Cash Allowance	(133.1)	/u
9	Total Allowance for Working Capital	557.0	/u
10	Utility Rate Base	16,281.1	/u

Comparison of Utility Rate Base - EGI - 2019 Actual & 2020 Actual

Line No.	Particulars ($ millions)	2019 Actual	2020 Actual	2020 Actual Over/(Under) 2019 Actual
		(a)	(b)	(c) = (b-a)
	Property, Plant and Equipment			
1	Gross Property, Plant and Equipment	19,765.5	20,582.1	816.6
2	Accumulated Depreciation	(7,188.7)	(7,571.2)	(382.5)
3	Net Property, Plant and Equipment	12,576.8	13,010.8	434.1
	Allowance for Working Capital			
4	Materials and Supplies	74.9	82.2	7.3
5	Customer Security Deposits	(91.0)	(81.8)	9.2
6	Prepaid Expenses	5.6	3.1	(2.5)
7	ABC Receivable/(Payable)	(30.2)	(22.3)	7.9
8	Balancing Gas	56.2	59.5	3.3
9	Gas in Storage	522.0	487.5	(34.5)
10	Cash Working Capital	24.9	23.0	(1.9)
11	Total Allowance for Working Capital	562.3	551.2	(11.1)
12	Total Utility Rate Base	13,139.0	13,562.0	423.0

Comparison of Utility Rate Base - EGI - 2020 Actual & 2021 Actual

Line No.	Particulars ($ millions)	2020 Actual	2021 Actual	2021 Actual Over/(Under) 2020 Actual
		(a)	(b)	(c) = (b-a)
	Property, Plant and Equipment			
1	Gross Property, Plant and Equipment	20,582.1	21,539.8	957.7
2	Accumulated Depreciation	(7,571.2)	(8,005.9)	(434.7)
3	Net Property, Plant and Equipment	13,010.8	13,533.9	523.1
	Allowance for Working Capital			
4	Materials and Supplies	82.2	92.5	10.3
5	Customer Security Deposits	(81.8)	(68.9)	12.9
6	Prepaid Expenses	3.1	4.7	1.6
7	ABC Receivable/(Payable)	(22.3)	(15.5)	6.8
8	Balancing Gas	59.5	59.5	(0.0)
9	Gas in Storage	487.5	594.7	107.2
10	Cash Working Capital	23.0	20.9	(2.1)
11	Total Allowance for Working Capital	551.2	687.7	136.5
12	Total Utility Rate Base	13,562.0	14,221.6	659.6

Comparison of Utility Rate Base - EGI - 2021 Actual & 2022 Estimate

Line No.	Particulars ($ millions)	2021 Actual	2022 Estimate	2022 Estimate Over/(Under) 2021 Actual	
		(a)	(b)	(c) = (b-a)	
	Property, Plant and Equipment				
1	Gross Property, Plant and Equipment	21,539.8	22,663.3	1,123.5	
2	Accumulated Depreciation	(8,005.9)	(8,417.8)	(411.9)	/u
3	Net Property, Plant and Equipment	13,533.9	14,245.4	711.6	/u
	Allowance for Working Capital				
4	Materials and Supplies	92.5	93.1	0.6	
5	Customer Security Deposits	(68.9)	(67.7)	1.2	
6	Prepaid Expenses	4.7	4.8	0.1	
7	ABC Receivable/(Payable)	(15.5)	(15.3)	0.2	
8	Balancing Gas	59.5	59.5	0.0	
9	Gas in Storage	594.7	776.1	181.4	
10	Cash Working Capital	20.9	5.4	(15.5)	
11	Total Allowance for Working Capital	687.7	855.9	168.2	
12	Total Utility Rate Base	14,221.6	15,101.3	879.7	/u

Comparison of Utility Rate Base - EGI - 2022 Estimate & 2023 Bridge Year

Line No.	Particulars ($ millions)	2022 Estimate	2023 Bridge Year	2023 Bridge Over/(Under) 2022 Estimate	
		(a)	(b)	(c) = (b-a)	
	Property, Plant and Equipment				
1	Gross Property, Plant and Equipment	22,663.3	23,874.8	1,211.5	/u
2	Accumulated Depreciation	(8,417.8)	(8,924.1)	(506.2)	/u
3	Net Property, Plant and Equipment	14,245.4	14,950.7	705.3	/u
	Allowance for Working Capital				
4	Materials and Supplies	93.1	101.5	8.4	
5	Customer Security Deposits	(67.7)	(64.0)	3.7	
6	Prepaid Expenses	4.8	4.8	0.0	
7	ABC Receivable/(Payable)	(15.3)	(17.0)	(1.7)	
8	Balancing Gas	59.5	59.5	0.0	
9	Gas in Storage	776.1	580.6	(195.5)	
10	Cash Working Capital	5.4	24.0	18.6	/u
11	Total Allowance for Working Capital	855.9	689.4	(166.5)	/u
12	Total Utility Rate Base	15,101.3	15,640.1	538.8	/u

Comparison of Utility Rate Base - EGI - 2023 Bridge Year & 2024 Test Year

Line No.	Particulars ($ millions)	2023 Bridge Year	2024 Test Year	2024 Test Over/(Under) 2023 Bridge	
		(a)	(b)	(c) = (b-a)	
	Property, Plant and Equipment				
1	Gross Property, Plant and Equipment	23,874.8	24,902.9	1,028.1	/u
2	Accumulated Depreciation	(8,924.1)	(9,178.9)	(254.8)	/u
3	Net Property, Plant and Equipment	14,950.7	15,724.0	773.3	/u
	Allowance for Working Capital				
4	Materials and Supplies	101.5	107.0	5.5	
5	Customer Security Deposits	(64.0)	(60.2)	3.8	
6	Prepaid Expenses	4.8	0.0	(4.8)	
7	ABC Receivable/(Payable)	(17.0)	(5.1)	11.9	
8	Balancing Gas	59.5	0.0	(59.5)	
9	Gas in Storage	580.6	648.4	67.8	
10	Cash Working Capital	24.0	(133.1)	(157.1)	/u
11	Total Allowance for Working Capital	689.4	557.0	(132.4)	/u
12	Total Utility Rate Base	15,640.1	16,281.1	641.0	/u

NET ASSETS - PROPERTY, PLANT AND EQUIPMENT

JASON VINAGRE, MANAGER REGULATORY ACCOUNTING

1. The purpose of this evidence is to provide Enbridge Gas's net Property, Plant and Equipment (PPE). PPE functional plant details, continuity and year-over-year comparisons from 2019 to 2021 actuals, 2022 Estimate, 2023 Bridge Year and 2024 Test Year are also provided. This evidence supports 2024 Rate Base set out at Exhibit 2, Tab 1, Schedule 1.

2. This evidence is organized as follows:
    1. PPE – Gross PPE and Accumulated Depreciation Introduction
    2. 2024 Test Year PPE

1. PPE – Gross PPE and Accumulated Depreciation Introduction

3. Enbridge Gas's annual average investment in net PPE is representative of gross in-service additions (inclusive of interest during construction, net of customer contributions and any retirement of prior in-service assets), offset by applicable accumulated depreciation (net of any retirements), calculated on an average of monthly averages basis. Attachment 1, pages 1-2 summarizes the average of monthly averages for gross PPE and accumulated depreciation respectively at a functional level for 2013 OEB-approved, and actuals for the 2013 to 2018 historical actual years for both EGD and Union. Attachment 1, pages 3-4 summarizes the average of monthly averages for gross PPE and accumulated depreciation respectively at a functional level for 2019 actual results to the 2024 Test Year Forecast for Enbridge Gas.

4. Attachment 2 summarizes the net PPE at a functional plant level for 2019 actual results to the 2024 Test Year Forecast for Enbridge Gas.

5. A detailed breakdown of the gross PPE and accumulated depreciation continuity by function and plant account, along with average of monthly average balances is provided at Attachments 3-8 for the years 2019 to 2024 Test Year.

6. EGD and Union have depreciated assets in accordance with the depreciation studies filed in EGD's 2013 Cost of Service[1] proceeding and Union's 2013 Cost of Service[2] proceeding. EGD's depreciation rates were approved in the 2014 to 2018 Custom Incentive Regulation (IR)[3] proceeding. The provision for depreciation for the 2024 Test Year has been calculated using the depreciation rates set out in the depreciation evidence provided at Exhibit 4, Tab 5, Schedule 1.

2. 2024 Test Year PPE

2.1. Opening PPE 2024 Test Year

7. Table 1 and Table 2 provide an overview and the year-over-year change in Gross PPE and Accumulated Depreciation respectively for Enbridge Gas over the deferred rebasing term. The tables provide the overall opening balances, activity and ending balances forecast for the 2024 Test Year. The tables also provide the average of monthly average balances by year which represent the inclusion of net PPE components in rate base.

[1] EB-2011-0354.
[2] EB-2011-0210.
[3] EB-2012-0459.

Table 1
Utility Property, Plant & Equipment - Continuity of Gross Assets

Line No.	Particulars ($ millions)	Utility	2019 Actual	2020 Actual	2021 Actual	2022 Estimate	2023 Bridge Year	2024 Test Year	
			(a)	(b)	(c)	(d)	(e)	(f)	
1	Opening Gross Property, Plant and Equipment	EGI	19,467.7	20,402.8	21,259.9	22,221.4	23,535.2	24,831.5	/u
2	Opening Balance Adjustments (1)	EGI	0.0	0.0	0.0	10.4	(69.6)	(317.5)	
3	In-service Additions	EGI	1,056.2	1,023.4	1,211.7	1,442.3	1,521.7	1,503.9	/u
4	Retirements and Disposals	EGI	(121.0)	(166.2)	(250.2)	(139.0)	(155.8)	(226.1)	/u
5	Adjustments and Other	EGI	0.0	0.0	0.1	0.1	0.0	0.0	
6	Closing Property, Plant and Equipment	EGI	20,402.8	21,259.9	22,221.4	23,535.2	24,831.5	25,791.8	/u
7	Average of Monthly Averages	EGI	19,765.5	20,582.1	21,539.8	22,663.3	23,874.8	24,902.9	/u
8	Variance of Gross PPE to Prior Year			857.1	961.5	1,313.8	1,296.3	960.3	/u
9	Variance of Avg of Monthly Avg to Prior Year			816.6	957.7	1,123.5	1,211.6	1,028.1	/u

Notes:
(1) Includes asset harmonization and unregulated cost allocation adjustments.

Table 2
Utility Property, Plant & Equipment - Continuity of Accumulated Depreciation

Line No.	Particulars ($ millions)	Utility	2019 Actual (a)	2020 Actual (b)	2021 Actual (c)	2022 Estimate (d)	2023 Bridge Year (e)	2024 Test Year (f)	
1	Opening Accumulated Depreciation	EGI	(6,960.9)	(7,393.0)	(7,799.7)	(8,126.9)	(8,626.9)	(9,137.7)	/u
2	Opening Balance Adjustments (1)	EGI	0.0	0.0	0.0	0.0	0.0	310.8	
3	Depreciation	EGI	(605.6)	(618.3)	(639.0)	(705.4)	(725.3)	(892.0)	/u
4	Retirements and Disposals	EGI	120.9	161.3	250.2	128.5	153.9	219.9	/u
5	Costs net of Proceeds	EGI	52.6	50.2	61.4	77.9	61.5	62.8	/u
6	Adjustments and Other	EGI	0.0	0.0	0.1	(1.0)	(1.0)	(0.5)	/u
7	Closing Accumulated Depreciation	EGI	(7,393.0)	(7,799.7)	(8,126.9)	(8,626.9)	(9,137.7)	(9,436.7)	/u
8	Average of Monthly Averages	EGI	(7,188.7)	(7,571.2)	(8,005.9)	(8,417.8)	(8,924.1)	(9,178.9)	/u
9	Variance of Accumulated Depreciation to Prior Year			(406.7)	(327.2)	(500.0)	(510.8)	(299.0)	/u
10	Variance of Avg of Monthly Avg to Prior Year			(382.5)	(434.7)	(411.9)	(506.2)	(254.8)	/u

Note:
(1) Includes asset harmonization and unregulated cost allocation adjustments.

8. Over the 2019 to 2023 deferred rebasing term, Enbridge Gas will have invested approximately $6.2 billion in gross in-service additions. In-service additions represent increases to rate base as a result of capital work on projects deemed ready for use. In-service additions follow the capital expenditures provided at Exhibit 2, Tab 5, Schedule 3.

9. Partially offsetting in-service additions are retirements of assets primarily where in-service additions are replacing assets. Such retirements during the deferred rebasing term include, but are not limited to, distribution and transmission mains and services, and the respective Customer Information Systems (CIS) of EGD and Union which were replaced with a new CIS in 2021.

10. Offsetting the impact of net PPE additions during the deferred rebasing term was the impact of depreciation. During the deferred rebasing term, Enbridge Gas will have incurred depreciation expense of $3.3 billion related to assets already in-service prior to 2019 as well as assets placed into service throughout 2019 to 2023.

2.2. In-service Additions 2024 Test Year

11. The 2024 Test Year Forecast for in-service additions represent increases to rate base as a result of capital work being declared in-service and ready to be used to serve Enbridge Gas customers. The annual in-service addition amounts vary from capital expenditure amounts due to the multi-year nature of capital projects and resulting timing differences.

12. Aside from timing variances between capital spend and in-service addition amounts, the material in-service additions for the 2024 Test Year follow the capital projects and expenditures as provided at Exhibit 2, Tab 5, Schedule 2, not including those projects that are multi-year projects expected to go into service after 2024.

13. Average net PPE for the 2024 Test Year is forecast to be $15,724.0 million /u
compared to $14,950.7 million for the 2023 Bridge Year. The $773.3 million /u
increase on a forecast basis is related to an estimated incremental $1.5 billion of in-service additions in 2024. Please see Exhibit 2, Tab 5, Schedule 2 for further details on 2024 Test Year capital expenditures.

14. Partially offsetting the $1.5 billion additions in 2024 from 2023 are expected
retirements in 2024 of approximately $226.1 million related primarily to distribution /u
system replacements, the retirement/replacement of TIS assets and the retirement of buildings that are being replaced and centralized. Further offsetting gross PPE
increases in 2024 is forecast depreciation expense of $892.0 million. /u

15. As provided at Exhibit 1, Tab 9, Schedule 1, Enbridge Gas proposes to include the net book value of integration capital forecasted at the end of 2023 in Enbridge Gas's rate base for the 2024 Test Year.

2.3. Asset Harmonization 2024 Test Year

16. Enbridge Gas is proposing to harmonize asset groups, plant accounts and depreciation rates into a single rate zone effective January 1, 2024. Details are provided at Exhibit 4, Tab 5, Schedule 1. The impact of gross asset and accumulated depreciation transfers between asset classes and functions, as well as associated depreciation impacts, have been reflected in the 2024 Test Year. The transfers were applied as part of restated opening 2024 Test Year balances which then allowed for asset additions, retirements and depreciation to be reflected in ending balances and the average of average amounts under the aligned methodologies. This resulted in no impact to net PPE as explained below.

17. As part of this asset harmonization, Enbridge Gas aligned the treatment for amortized assets. The harmonization resulted in a $300.2 million reduction in gross PPE related to the retirement of fully amortized assets (computer software, hardware, tools & work equipment, and regulators) offset by a $300.2 million reduction in associated accumulated depreciation which results in no impact to net PPE. These retirements have been reflected in opening January 1, 2024, gross PPE and accumulated deprecation amounts, as shown in Table 3 and 4.

18. Further, as of January 1, 2024, Enbridge Gas is proposing to implement a harmonized unregulated storage cost allocation methodology. Details of this harmonized methodology is provided at Exhibit 1, Tab 13, Schedule 2. The harmonization resulted in a $17.3 million transfer of gross PPE from the utility to the unregulated business, partially offset by related accumulated depreciation of $10.6 million. These amounts are reflected as of January 1, 2024, as part of the restated opening balance in gross utility assets and accumulated depreciation.

19. Table 3 and 4 provide the summary of the results of the Asset Harmonization and Unregulated Storage Cost Allocation in relation to the 2024 Test Year opening balances for Gross PPE and Accumulated Depreciation. These harmonization impacts are provided at Attachment 8.

Table 3
2024 Test Year Utility Property, Plant and Equipment
Gross Assets

Line No.	Particulars ($ millions)	Opening Gross Property, Plant and Equipment	Asset Harmonization Adjustments	Unregulated Cost Allocation Adjustments	Restated Opening Gross Property, Plant and Equipment	
		(a)	(b)	(c)	(d) = (a+b+c)	
1	Distribution Plant	17,791.4	(970.8)	0.0	16,820.6	/u
2	Transmission Plant	4,303.7	658.9	0.0	4,962.6	
3	Storage Plant	1,549.3	21.5	0.0	1,570.8	
4	General Plant	1,183.7	(9.7)	(17.3)	1,156.7	
5	Other Plant	3.3	0.0	0.0	3.3	
6	Total	24,831.5	(300.2)	(17.3)	24,514.0	/u

Table 4
2024 Test Year Utility Property, Plant and Equipment
Accumulated Depreciation

Line No.	Particulars ($ millions)	Opening Accumulated Depreciation	Asset Harmonization Adjustments	Unregulated Cost Allocation Adjustments	Restated Opening Accumulated Depreciation	
		(a)	(b)	(c)	(d) = (a+b+c)	
1	Distribution Plant	(6,433.7)	370.5	0.0	(6,063.2)	/u
2	Transmission Plant	(1,411.4)	(207.4)	0.0	(1,618.9)	
3	Storage Plant	(559.9)	10.6	0.0	(549.3)	
4	General Plant	(729.8)	126.5	10.6	(592.7)	
5	Other Plant	(2.9)	0.0	0.0	(2.9)	
6	Total	(9,137.7)	300.2	10.6	(8,826.9)	/u

Gross Property, Plant and Equipment Summary - Average of Monthly Averages

Line No.	Particulars ($ millions)	Utility	2013 OEB-Approved	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Distribution Plant	EGD	5,998.3	6,001.9	6,400.6	6,735.6	7,715.0	8,264.5	8,585.5
2	Underground Storage Plant	EGD	333.5	342.4	359.6	370.6	385.0	410.7	425.1
3	General Plant	EGD	424.5	414.5	466.4	491.9	499.2	563.8	594.1
4	Other Plant	EGD	(6.9)	(9.5)	(10.0)	(11.2)	(10.8)	(10.2)	(10.2)
5	Total		6,749.4	6,749.3	7,216.6	7,586.9	8,588.4	9,228.8	9,594.5
6	Distribution Plant - North and South	Union	3,822.4	3,862.8	4,026.4	4,168.8	4,366.6	4,604.7	4,834.8
7	Transmission Plant	Union	1,736.9	1,724.5	1,816.1	2,022.4	2,455.5	3,030.0	3,398.7
8	Underground Storage Plant	Union	507.6	526.0	529.0	534.1	543.6	650.4	800.1
9	Local Storage Plant	Union	22.8	20.8	24.3	25.8	26.7	28.8	30.7
10	Intangible Plant	Union	7.7	7.7	7.6	7.6	7.5	5.3	1.7
11	General Plant	Union	264.2	259.5	270.8	270.8	283.0	309.0	332.5
12	Total		6,361.5	6,401.2	6,674.3	7,029.5	7,683.0	8,628.2	9,398.6

Accumulated Depreciation Summary - Average of Monthly Averages

Line No.	Particulars ($ millions)	Utility	2013 OEB-Approved	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Distribution Plant	EGD	(2,519.2)	(2,474.9)	(2,552.1)	(2,575.0)	(2,587.4)	(2,655.5)	(2,734.5)
2	Underground Storage Plant	EGD	(115.0)	(121.4)	(128.1)	(131.2)	(129.1)	(136.6)	(142.0)
3	General Plant	EGD	(169.2)	(159.1)	(220.5)	(274.8)	(300.8)	(335.9)	(402.9)
4	Other Plant	EGD	(0.7)	(0.5)	(0.1)	0.2	(0.1)	1.5	1.5
5	Total		(2,804.1)	(2,755.9)	(2,900.8)	(2,980.8)	(3,017.4)	(3,126.5)	(3,277.9)
6	Distribution Plant - North and South	Union	(1,709.5)	(1,688.3)	(1,752.7)	(1,828.8)	(1,921.6)	(2,024.5)	(2,125.2)
7	Transmission Plant	Union	(679.2)	(689.5)	(724.8)	(767.6)	(819.9)	(882.3)	(953.4)
8	Underground Storage Plant	Union	(226.4)	(245.7)	(256.6)	(269.6)	(279.7)	(292.7)	(293.0)
9	Local Storage Plant	Union	(11.2)	(10.9)	(11.3)	(12.0)	(12.8)	(13.7)	(14.7)
10	Intangible Plant	Union	(6.2)	(6.2)	(6.3)	(6.5)	(6.6)	(4.6)	(1.1)
11	General Plant	Union	(121.7)	(105.7)	(117.2)	(110.4)	(108.6)	(129.7)	(136.8)
12	Total		(2,754.1)	(2,746.2)	(2,868.9)	(2,994.8)	(3,149.2)	(3,347.5)	(3,524.2)

Gross Property, Plant and Equipment Summary - Average of Monthly Averages

Line No.	Particulars ($ millions)	Utility	2019 Actual (a)	2020 Actual (b)	2021 Actual (c)	2022 Estimate (d)	2023 Bridge Year (e)	2024 Test Year (f)	
1	Distribution Plant	EGD(1)	8,923.5	9,209.1	9,643.2	10,261.1	10,746.3		
2	Underground Storage Plant	EGD	436.1	442.2	485.6	568.0	597.4		
3	General Plant	EGD	616.9	657.9	675.7	599.5	663.3		
4	Other Plant	EGD	1.7	1.7	1.7	1.7	1.7		
5	Total		9,978.2	10,310.8	10,806.2	11,430.3	12,008.6		
6	Distribution Plant - South Operations	Union(2)	3,154.2	3,332.6	3,540.8	3,797.6	4,027.4		/u
7	Distribution Plant - Northern/Eastern Operations	Union	1,940.9	2,049.0	2,134.6	2,243.1	2,379.7		/u
8	Transmission Plant	Union	3,491.7	3,636.8	3,767.4	3,916.6	4,107.2		
9	Underground Storage Plant	Union	803.9	812.3	819.7	809.8	843.8		
10	Local Storage Plant	Union	31.9	32.3	32.0	34.3	37.7		
11	Intangible Plant	Union	1.7	1.7	1.7	1.7	1.7		
12	General Plant	Union	363.0	406.5	437.5	430.0	468.6		
13	Total		9,787.3	10,271.2	10,733.6	11,233.0	11,866.1		/u
14	Distribution Plant	EGI	14,018.5	14,590.7	15,318.6	16,301.8	17,153.5	17,112.2	/u
15	Transmission Plant	EGI	3,491.7	3,636.8	3,767.4	3,916.6	4,107.2	5,012.9	
16	Storage Plant	EGI	1,272.0	1,286.8	1,337.3	1,412.1	1,478.9	1,602.8	
17	General Plant	EGI	980.0	1,064.4	1,113.1	1,029.5	1,131.9	1,171.5	
18	Other Plant	EGI	3.3	3.3	3.3	3.3	3.3	3.3	
19	Total		19,765.5	20,582.1	21,539.8	22,663.3	23,874.8	24,902.9	/u

Notes:
(1) EGD rate zone.
(2) Union rate zones.

Accumulated Depreciation Summary - Average of Monthly Averages

Line No.	Particulars ($ millions)	Utility	2019 Actual (a)	2020 Actual (b)	2021 Actual (c)	2022 Estimate (d)	2023 Bridge Year (e)	2024 Test Year (f)	
1	Distribution Plant	EGD(1)	(2,866.4)	(2,933.5)	(3,071.5)	(3,357.5)	(3,541.0)		/u
2	Underground Storage Plant	EGD	(137.4)	(142.9)	(148.5)	(157.2)	(164.5)		
3	General Plant	EGD	(439.1)	(480.3)	(504.9)	(428.2)	(486.2)		
4	Other Plant	EGD	(1.4)	(1.4)	(1.4)	(1.5)	(1.5)		
5	Total		(3,444.2)	(3,558.1)	(3,726.3)	(3,944.4)	(4,193.1)		/u
6	Distribution Plant - South Operations	Union(2)	(1,370.3)	(1,441.1)	(1,515.5)	(1,590.2)	(1,660.7)		/u
7	Distribution Plant - Northern/Eastern Operations	Union	(870.5)	(923.8)	(980.1)	(1,037.3)	(1,094.7)		/u
8	Transmission Plant	Union	(1,023.1)	(1,104.4)	(1,188.6)	(1,276.1)	(1,364.9)		
9	Underground Storage Plant	Union	(298.2)	(316.8)	(335.4)	(349.6)	(362.4)		
10	Local Storage Plant	Union	(15.8)	(16.8)	(17.8)	(18.7)	(19.9)		
11	Intangible Plant	Union	(1.1)	(1.2)	(1.3)	(1.5)	(1.5)		
12	General Plant	Union	(165.6)	(209.0)	(240.9)	(199.9)	(226.8)		
13	Total		(3,744.5)	(4,013.1)	(4,279.6)	(4,473.4)	(4,730.9)		/u
14	Distribution Plant	EGI	(5,107.1)	(5,298.4)	(5,567.2)	(5,985.0)	(6,296.5)	(6,318.2)	/u
15	Transmission Plant	EGI	(1,023.1)	(1,104.4)	(1,188.6)	(1,276.1)	(1,364.9)	(1,675.2)	
16	Storage Plant	EGI	(451.3)	(476.6)	(501.6)	(525.6)	(546.7)	(568.9)	
17	General Plant	EGI	(604.7)	(689.3)	(745.8)	(628.2)	(713.1)	(613.6)	
18	Other Plant	EGI	(2.5)	(2.6)	(2.7)	(2.9)	(2.9)	(2.9)	
19	Total		(7,188.7)	(7,571.2)	(8,005.9)	(8,417.8)	(8,924.1)	(9,178.9)	/u

Notes:
(1) EGD rate zone.
(2) Union rate zones.

2019 Actual Net Utility Property, Plant and Equipment - EGI - Average of Monthly Averages

Line No.	Particulars ($ millions)	Rate Zone	Gross Property, Plant and Equipment	Accumulated Depreciation	Actual Net Property, Plant and Equipment
			(a)	(b)	(c) = (a+b)
1	Distribution Plant	EGD	8,923.5	(2,866.4)	6,057.1
2	Underground Storage Plant	EGD	436.1	(137.4)	298.7
3	General Plant	EGD	616.9	(439.1)	177.8
4	Other Plant	EGD	1.7	(1.4)	0.3
5	Total		9,978.2	(3,444.2)	6,533.9
6	Distribution Plant - South Operations	Union	3,154.2	(1,370.3)	1,783.9
7	Distribution Plant - Northern/Eastern Operations	Union	1,940.9	(870.5)	1,070.4
8	Transmission Plant	Union	3,491.7	(1,023.1)	2,468.6
9	Underground Storage Plant	Union	803.9	(298.2)	505.8
10	Local Storage Plant	Union	31.9	(15.8)	16.2
11	Intangible Plant	Union	1.7	(1.1)	0.5
12	General Plant	Union	363.0	(165.6)	197.4
13	Total		9,787.3	(3,744.5)	6,042.8
14	Distribution Plant	EGI	14,018.5	(5,107.1)	8,911.4
15	Transmission Plant	EGI	3,491.7	(1,023.1)	2,468.6
16	Storage Plant	EGI	1,272.0	(451.3)	820.6
17	General Plant	EGI	980.0	(604.7)	375.3
18	Other Plant	EGI	3.3	(2.5)	0.9
19	Total		19,765.5	(7,188.7)	12,576.8

2020 Actual Net Utility Property, Plant and Equipment - EGI - Average of Monthly Averages

Line No.	Particulars ($ millions)	Rate Zone	Gross Property, Plant and Equipment	Accumulated Depreciation	Actual Net Property, Plant and Equipment
			(a)	(b)	(c) = (a+b)
1	Distribution Plant	EGD	9,209.1	(2,933.5)	6,275.5
2	Underground Storage Plant	EGD	442.2	(142.9)	299.3
3	General Plant	EGD	657.9	(480.3)	177.6
4	Other Plant	EGD	1.7	(1.4)	0.3
5	Total		10,310.8	(3,558.1)	6,752.7
6	Distribution Plant - South Operations	Union	3,332.6	(1,441.1)	1,891.4
7	Distribution Plant - Northern/Eastern Operations	Union	2,049.0	(923.8)	1,125.3
8	Transmission Plant	Union	3,636.8	(1,104.4)	2,532.4
9	Underground Storage Plant	Union	812.3	(316.8)	495.4
10	Local Storage Plant	Union	32.3	(16.8)	15.5
11	Intangible Plant	Union	1.7	(1.2)	0.5
12	General Plant	Union	406.5	(209.0)	197.5
13	Total		10,271.2	(4,013.1)	6,258.1
14	Distribution Plant	EGI	14,590.7	(5,298.4)	9,292.2
15	Transmission Plant	EGI	3,636.8	(1,104.4)	2,532.4
16	Storage Plant	EGI	1,286.8	(476.6)	810.3
17	General Plant	EGI	1,064.4	(689.3)	375.1
18	Other Plant	EGI	3.3	(2.6)	0.8
19	Total		20,582.1	(7,571.2)	13,010.8

2021 Actual Net Utility Property, Plant and Equipment - EGI - Average of Monthly Averages

Line No.	Particulars ($ millions)	Rate Zone	Gross Property, Plant and Equipment	Accumulated Depreciation	Actual Net Property, Plant and Equipment
			(a)	(b)	(c) = (a+b)
1	Distribution Plant	EGD	9,643.2	(3,071.5)	6,571.7
2	Underground Storage Plant	EGD	485.6	(148.5)	337.1
3	General Plant	EGD	675.7	(504.9)	170.8
4	Other Plant	EGD	1.7	(1.4)	0.2
5	Total		10,806.2	(3,726.3)	7,079.8
6	Distribution Plant - South Operations	Union	3,540.8	(1,515.5)	2,025.2
7	Distribution Plant - Northern/Eastern Operations	Union	2,134.6	(980.1)	1,154.5
8	Transmission Plant	Union	3,767.4	(1,188.6)	2,578.8
9	Underground Storage Plant	Union	819.7	(335.4)	484.3
10	Local Storage Plant	Union	32.0	(17.8)	14.2
11	Intangible Plant	Union	1.7	(1.3)	0.4
12	General Plant	Union	437.5	(240.9)	196.6
13	Total		10,733.6	(4,279.6)	6,454.0
14	Distribution Plant	EGI	15,318.6	(5,567.2)	9,751.4
15	Transmission Plant	EGI	3,767.4	(1,188.6)	2,578.8
16	Storage Plant	EGI	1,337.3	(501.6)	835.7
17	General Plant	EGI	1,113.1	(745.8)	367.4
18	Other Plant	EGI	3.3	(2.7)	0.6
19	Total		21,539.8	(8,005.9)	13,533.9

2022 Estimate Net Utility Property, Plant and Equipment - EGI - Average of Monthly Averages

Line No.	Particulars ($ millions)	Rate Zone	Gross Property, Plant and Equipment	Accumulated Depreciation	Estimate Net Property, Plant and Equipment	
			(a)	(b)	(c) = (a+b)	
1	Distribution Plant	EGD	10,261.1	(3,357.5)	6,903.6	/u
2	Underground Storage Plant	EGD	568.0	(157.2)	410.8	
3	General Plant	EGD	599.5	(428.2)	171.3	
4	Other Plant	EGD	1.7	(1.5)	0.2	
5	Total		11,430.3	(3,944.4)	7,485.9	/u
6	Distribution Plant - South Operations	Union	3,797.6	(1,590.2)	2,207.4	
7	Distribution Plant - Northern/Eastern Operations	Union	2,243.1	(1,037.3)	1,205.8	
8	Transmission Plant	Union	3,916.6	(1,276.1)	2,640.4	
9	Underground Storage Plant	Union	809.8	(349.6)	460.1	
10	Local Storage Plant	Union	34.3	(18.7)	15.6	
11	Intangible Plant	Union	1.7	(1.5)	0.2	
12	General Plant	Union	430.0	(199.9)	230.0	
13	Total		11,233.0	(4,473.4)	6,759.6	
14	Distribution Plant	EGI	16,301.8	(5,985.0)	10,316.8	/u
15	Transmission Plant	EGI	3,916.6	(1,276.1)	2,640.4	
16	Storage Plant	EGI	1,412.1	(525.6)	886.5	
17	General Plant	EGI	1,029.5	(628.2)	401.3	
18	Other Plant	EGI	3.3	(2.9)	0.4	
19	Total		22,663.3	(8,417.8)	14,245.4	/u

2023 Bridge Year Net Utility Property, Plant and Equipment - EGI - Average of Monthly Averages

Line No.	Particulars ($ millions)	Rate Zone	Gross Property, Plant and Equipment	Accumulated Depreciation	Bridge Year Net Property, Plant and Equipment	
			(a)	(b)	(c) = (a+b)	
1	Distribution Plant	EGD	10,746.3	(3,541.0)	7,205.3	/u
2	Underground Storage Plant	EGD	597.4	(164.5)	432.9	
3	General Plant	EGD	663.3	(486.2)	177.0	
4	Other Plant	EGD	1.7	(1.5)	0.2	
5	Total		12,008.6	(4,193.1)	7,815.5	/u
6	Distribution Plant - South Operations	Union	4,027.4	(1,660.7)	2,366.7	/u
7	Distribution Plant - Northern/Eastern Operations	Union	2,379.7	(1,094.7)	1,285.0	/u
8	Transmission Plant	Union	4,107.2	(1,364.9)	2,742.3	
9	Underground Storage Plant	Union	843.8	(362.4)	481.5	
10	Local Storage Plant	Union	37.7	(19.9)	17.8	
11	Intangible Plant	Union	1.7	(1.5)	0.2	
12	General Plant	Union	468.6	(226.8)	241.8	
13	Total		11,866.1	(4,730.9)	7,135.2	/u
14	Distribution Plant	EGI	17,153.5	(6,296.5)	10,857.0	/u
15	Transmission Plant	EGI	4,107.2	(1,364.9)	2,742.3	
16	Storage Plant	EGI	1,478.9	(546.7)	932.2	
17	General Plant	EGI	1,131.9	(713.1)	418.8	
18	Other Plant	EGI	3.3	(2.9)	0.4	
19	Total		23,874.8	(8,924.1)	14,950.7	/u

2024 Test Year Net Utility Property, Plant and Equipment - EGI - Average of Monthly Averages

Line No.	Particulars ($ millions)	Gross Property, Plant and Equipment	Accumulated Depreciation	Test Year Net Property, Plant and Equipment	
		(a)	(b)	(c) = (a+b)	
1	Distribution Plant	17,112.2	(6,318.2)	10,794.0	/u
2	Transmission Plant	5,012.9	(1,675.2)	3,337.7	
3	Storage Plant	1,602.8	(568.9)	1,033.9	
4	General Plant	1,171.5	(613.6)	557.9	
5	Other Plant	3.3	(2.9)	0.4	
6	Total	24,902.9	(9,178.9)	15,724.0	/u

Utility Gross Distribution Plant - EGI - Year End Balances and Average of Monthly Averages
2019 Actual

Line No.	Particulars ($ millions)	Dec. 2018 Opening Balance	Additions	Retirements	Dec. 2019 Closing Balance	Regulatory Adjustment	Dec. 2019 Utility Balance	Average of Monthly Averages
		(a)	(b)	(c)	(d) = (a+b+c)	(e)	(f) = (d+e)	(g)
	EGD Rate Zone Distribution Plant							
1	Renewable Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	Land	23.2	20.7	(0.1)	43.8	0.0	43.8	24.0
3	Offers to purchase	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	Land rights intangibles	63.8	0.0	0.0	63.8	0.0	63.8	63.8
5	Structures and improvements	143.7	2.5	(0.2)	146.0	(0.3)	145.7	144.8
6	Services, house reg & meter install.	2,954.9	146.2	(9.9)	3,091.2	0.0	3,091.2	3,018.7
7	Mains	4,530.9	214.0	(52.9)	4,692.0	(2.2)	4,689.8	4,601.8
8	NGV station compressors	3.7	0.7	0.0	4.5	0.0	4.5	4.2
9	Measuring and regulating equip.	608.2	22.8	(1.1)	629.8	(0.5)	629.3	619.5
10	Meters	429.4	73.7	(5.5)	497.6	0.0	497.6	446.7
11	Subtotal	8,757.8	480.5	(69.7)	9,168.6	(3.1)	9,165.5	8,923.5
	Union Rate Zones Distribution Plant - Southern Operations							
12	Land	11.3	0.5	0.0	11.8	0.0	11.8	11.4
13	Land rights	7.9	0.3	0.0	8.2	0.0	8.2	8.0
14	Structures and improvements	134.1	2.5	0.0	136.6	0.0	136.6	134.1
15	Services - metallic	124.1	2.2	(0.3)	126.0	0.0	126.0	124.5
16	Services - plastic	897.9	29.7	(1.9)	925.7	0.0	925.7	909.3
17	Regulators	83.8	7.3	0.0	91.1	0.0	91.1	86.6
18	House regulators & meter installations	71.1	2.5	(0.1)	73.5	0.0	73.5	71.3
19	Mains - metallic	522.0	35.7	(0.4)	557.3	0.0	557.3	527.7
20	Mains - plastic	645.9	28.7	(0.5)	674.1	0.0	674.1	651.9

Utility Gross Distribution Plant - EGI - Year End Balances and Average of Monthly Averages (Continued)
2019 Actual

Line No.	Particulars ($ millions)	Dec. 2018 Opening Balance	Additions	Retirements	Dec. 2019 Closing Balance	Regulatory Adjustment	Dec. 2019 Utility Balance	Average of Monthly Averages
		(a)	(b)	(c)	(d) = (a+b+c)	(e)	(f) = (d+e)	(g)
21	Measuring & regulating equipment	43.7	6.6	0.0	50.4	0.0	50.4	44.3
22	Meters	334.0	29.9	(8.9)	355.0	0.0	355.0	344.9
23	Regulatory Overheads	226.0	38.6	0.0	264.6	0.0	264.6	240.4
24	Subtotal	3,101.8	184.5	(12.1)	3,274.2	0.0	3,274.2	3,154.2
	Union Rate Zones Distribution Plant - Northern & Eastern Operations							
25	Land	4.5	0.2	0.0	4.7	0.0	4.7	4.5
26	Land rights	10.3	0.2	0.0	10.5	0.0	10.5	10.4
27	Structures and improvements	66.9	0.6	0.0	67.5	0.0	67.5	66.9
28	Services - metallic	106.4	2.3	(0.2)	108.5	0.0	108.5	107.2
29	Services - plastic	465.8	13.4	(1.0)	478.2	0.0	478.2	470.0
30	Regulators	31.9	9.5	0.0	41.4	0.0	41.4	35.5
31	House regulators & meter installations	40.3	0.6	(0.0)	40.9	0.0	40.9	40.4
32	Mains - metallic	585.9	40.0	(0.5)	625.4	0.0	625.4	589.7
33	Mains - plastic	232.9	5.6	(0.2)	238.4	0.0	238.4	233.4
34	Measuring & regulating equipment	139.8	6.8	(0.6)	145.9	0.0	145.9	139.9
35	Meters	83.9	7.5	(2.6)	88.8	0.0	88.8	86.4
36	Regulatory Overheads	153.3	15.5	0.0	168.7	0.0	168.7	156.6
37	Subtotal	1,921.6	102.1	(5.1)	2,018.7	0.0	2,018.7	1,940.9
38	EGI Total	13,781.2	767.2	(86.9)	14,461.4	(3.1)	14,458.4	14,018.5

Utility Transmission Plant - EGI - Year End Balances and Average of Monthly Averages
2019 Actual

Line No.	Particulars ($ millions)	Dec. 2018 Opening Balance	Additions	Retirements	Dec. 2019 Closing Balance	Regulatory Adjustment	Dec. 2019 Utility Balance	Average of Monthly Averages
		(a)	(b)	(c)	(d) = (a+b+c)	(e)	(f) = (d+e)	(g)
	Union Rate Zones Transmission Plant							
1	Land	73.3	2.1	0.0	75.4	0.0	75.4	73.7
2	Land rights	62.2	3.9	0.0	66.2	0.0	66.2	63.0
3	Structures & improvements	164.3	1.7	(0.0)	165.9	0.0	165.9	164.6
4	Mains	1,784.7	97.7	(1.9)	1,880.4	0.0	1,880.4	1,800.6
5	Compressor equipment	939.0	1.9	0.0	940.9	0.0	940.9	939.5
6	Measuring & regulating equipment	272.7	26.5	(0.1)	299.1	0.0	299.1	276.2
7	Line Pack Gas	7.4	0.0	0.0	7.5	0.0	7.5	7.4
8	Regulatory Overheads	154.3	22.5	0.0	176.8	0.0	176.8	166.7
9	Total	3,458.0	156.2	(2.0)	3,612.3	0.0	3,612.3	3,491.7

Utility Storage Plant - EGI - Year End Balances and Average of Monthly Averages
2019 Actual

Line No.	Particulars ($ millions)	Dec. 2018 Opening Balance	Additions	Retirements	Dec. 2019 Closing Balance	Regulatory Adjustment	Dec. 2019 Utility Balance	Average of Monthly Averages
		(a)	(b)	(c)	(d) = (a+b+c)	(e)	(f) = (d+e)	(g)
	EGD Rate Zone Underground Storage Plant							
1	Crowland storage	4.2	0.0	0.0	4.2	0.0	4.2	4.2
2	Land and gas storage rights	46.3	0.0	0.0	46.3	(1.0)	45.3	45.3
3	Structures and improvements	31.3	0.0	(0.2)	31.1	(0.1)	31.0	31.1
4	Wells	57.5	4.1	(2.4)	59.2	0.0	59.2	59.2
5	Well equipment	11.8	0.1	(1.0)	10.9	0.0	10.9	11.1
6	Field Lines	102.3	3.8	0.0	106.1	0.0	106.1	105.3
7	Compressor equipment	135.9	0.6	(1.1)	135.4	(0.5)	135.0	135.4
8	Measuring and regulating equipment	11.2	0.0	(0.1)	11.1	0.0	11.1	11.2
9	Base pressure gas	33.4	0.0	0.0	33.4	0.0	33.4	33.4
10	Subtotal	433.8	8.6	(4.7)	437.6	(1.5)	436.1	436.1
	Union Rate Zones Local Storage Plant							
11	Land	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	Structures and improvements	4.7	0.0	0.0	4.7	0.0	4.7	4.7
13	Gas holders - storage	4.6	0.0	0.0	4.6	0.0	4.6	4.6
14	Gas holders - equipment	20.0	0.0	0.0	20.0	0.0	20.0	20.0
15	Regulatory Overheads	1.8	1.3	0.0	3.1	0.0	3.1	2.6
16	Subtotal	31.1	1.3	0.0	32.4	0.0	32.4	31.9

Utility Storage Plant - EGI - Year End Balances and Average of Monthly Averages (Continued)
2019 Actual

Line No.	Particulars ($ millions)	Dec. 2018 Opening Balance	Additions	Retirements	Dec. 2019 Closing Balance	Regulatory Adjustment	Dec. 2019 Utility Balance	Average of Monthly Averages
		(a)	(b)	(c)	(d) = (a+b+c)	(e)	(f) = (d+e)	(g)
	Union Rate Zones Underground Storage Plant							
17	Land	5.5	0.0	0.0	5.6	0.0	5.6	5.6
18	Land rights	32.0	0.0	0.0	32.0	0.0	32.0	32.0
19	Structures and improvements	68.9	0.6	(0.7)	68.8	0.0	68.8	68.6
20	Wells	46.9	0.4	0.0	47.3	0.0	47.3	46.9
21	Field Lines	46.4	0.5	0.0	46.9	0.0	46.9	46.4
22	Compressor equipment	465.6	4.4	0.0	470.0	0.0	470.0	466.6
23	Measuring and regulating equipment	86.2	1.7	(2.8)	85.1	0.0	85.1	85.1
24	Base pressure gas	36.6	0.0	0.0	36.6	0.0	36.6	36.6
25	Regulatory Overheads	16.2	1.4	0.0	17.6	0.0	17.6	16.3
26	Subtotal	804.2	9.0	(3.4)	809.7	0.0	809.7	803.9
27	EGI Total	1,269.0	18.9	(8.1)	1,279.8	(1.5)	1,278.2	1,272.0

Utility General Plant - EGI - Year End Balances and Average of Monthly Averages
2019 Actual

Line No.	Particulars ($ millions)	Dec. 2018 Opening Balance (a)	Additions (b)	Retirements (c)	Dec. 2019 Closing Balance (d) = (a+b+c)	Regulatory Adjustment (e)	Dec. 2019 Utility Balance (f) = (d+e)	Average of Monthly Averages (g)
	EGD Rate Zone General Plant							
1	Lease improvements	0.1	0.0	0.0	0.1	(0.2)	(0.1)	(0.1)
2	Office furniture and equipment	20.5	0.5	(0.0)	20.9	0.0	20.9	20.7
3	Transportation equipment	51.5	14.2	(2.5)	63.2	(0.1)	63.1	50.8
4	NGV conversion kits	2.2	0.3	0.0	2.5	0.0	2.5	2.3
5	Heavy work equipment	17.9	0.1	(0.6)	17.3	0.0	17.3	17.4
6	Tools and work equipment	50.7	0.2	(0.1)	50.9	0.0	50.9	50.9
7	Rental equipment	1.6	0.2	0.0	1.8	0.0	1.8	1.7
8	NGV rental compressors	7.1	0.2	0.0	7.4	0.0	7.4	7.3
9	NGV cylinders	0.6	0.0	0.0	0.6	0.0	0.6	0.6
10	Communication structures & equip.	4.1	0.0	(0.4)	3.7	0.0	3.7	4.1
11	Computer equipment	26.4	4.3	(0.7)	30.0	0.0	30.0	27.9
12	Software Aquired/Developed	215.2	33.4	(13.6)	235.0	0.0	235.0	214.1
13	CIS	127.1	0.0	0.0	127.1	0.0	127.1	127.1
14	WAMS	92.1	0.2	0.0	92.2	0.0	92.2	92.2
15	Subtotal	617.0	53.6	(17.9)	652.7	(0.3)	652.5	616.9
	Union Rate Zones General Plant							
16	Land	0.6	0.0	0.0	0.6	0.0	0.6	0.6
17	Structures & improvements	69.5	3.5	0.0	73.0	0.0	73.0	69.9
18	Office furniture and equipment	10.1	(0.0)	0.0	10.1	0.0	10.1	10.1
19	Office equipment - computers	87.0	33.8	0.0	120.8	0.0	120.8	100.1
20	Transportation equipment	61.1	8.0	(5.4)	63.7	0.0	63.7	61.5

Utility General Plant - EGI - Year End Balances and Average of Monthly Averages (Continued)
2019 Actual

Line No.	Particulars ($ millions)	Dec. 2018 Opening Balance	Additions	Retirements	Dec. 2019 Closing Balance	Regulatory Adjustment	Dec. 2019 Utility Balance	Average of Monthly Averages
		(a)	(b)	(c)	(d) = (a+b+c)	(e)	(f) = (d+e)	(g)
21	Heavy work equipment	15.8	4.3	(0.7)	19.3	0.0	19.3	16.2
22	Tools and work equipment	35.6	1.6	0.0	37.2	0.0	37.2	36.1
23	NGV fuel equipment	1.3	0.6	0.0	2.0	0.0	2.0	1.9
24	Communication equipment	13.9	0.2	0.0	14.1	0.0	14.1	14.0
25	Regulatory Overheads	49.0	8.3	0.0	57.3	0.0	57.3	52.8
26	Subtotal	343.9	60.3	(6.1)	398.1	0.0	398.1	363.0
27	EGI Total	960.9	113.9	(24.0)	1,050.8	(0.3)	1,050.6	980.0

Utility Other Plant -EGI - Year End Balances and Average of Monthly Averages
2019 Actual

Line No.	Particulars ($ millions)	Dec. 2018 Opening Balance	Additions	Retirements	Dec. 2019 Closing Balance	Regulatory Adjustment	Dec. 2019 Utility Balance	Average of Monthly Averages
		(a)	(b)	(c)	(d) = (a+b+c)	(e)	(f) = (d+e)	(g)
	EGD Rate Zone Plant held for future use							
1	Inactive services	1.7	0.0	0.0	1.7	0.0	1.7	1.7
	Union Rate Zones Intangible Plant							
2	Franchises and consents	1.2	0.0	0.0	1.2	0.0	1.2	1.2
3	Other intangible plant	0.5	0.0	0.0	0.5	0.0	0.5	0.5
4	Subtotal	1.7	0.0	0.0	1.7	0.0	1.7	1.7
5	EGI Total	3.3	0.0	0.0	3.3	0.0	3.3	3.3

Utility Distribution Plant - EGI - Continuity of Accumulated Depreciation Year End Balances and Average of Monthly Averages
2019 Actual

Line No.	Particulars ($ millions)	Dec. 2018 Opening Balance (a)	Additions (b)	Retirements (c)	Costs Net of Proceeds (d)	Dec. 2019 Closing Balance (e) = (a+b+c+d)	Regulatory Adjustment (f)	Dec. 2019 Utility Balance (g) = (e+f)	Average of Monthly Averages (h)
	EGD Rate Zone Distribution Plant								
1	Renewable Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	Land rights intangibles	(4.2)	(0.8)	0.0	0.0	(5.0)	0.0	(5.0)	(4.6)
3	Structures and improvements	(25.1)	(9.1)	0.2	0.0	(34.0)	0.3	(33.7)	(29.4)
4	Services, house reg & meter install.	(1,027.4)	(68.9)	9.9	20.8	(1,065.6)	0.0	(1,065.6)	(1,049.6)
5	Mains	(1,281.7)	(102.1)	52.9	16.7	(1,314.1)	2.0	(1,312.1)	(1,299.7)
6	NGV station compressors	(2.7)	(0.3)	0.0	0.0	(3.0)	0.0	(3.0)	(2.8)
7	Measuring and regulating equip.	(231.0)	(12.8)	1.1	(0.4)	(243.1)	0.5	(242.6)	(236.7)
8	Meters	(232.0)	(41.0)	5.5	5.5	(262.1)	0.0	(262.1)	(243.6)
9	Subtotal	(2,804.1)	(234.9)	69.6	42.6	(2,926.8)	2.9	(2,923.9)	(2,866.4)
	Union Rate Zones Distribution Plant - Southern Operations								
10	Land rights	(2.0)	(0.1)	0.0	0.0	(2.1)	0.0	(2.1)	(2.1)
11	Structures and improvements	(38.3)	(3.0)	0.0	0.0	(41.3)	0.0	(41.3)	(39.8)
12	Services - metallic	(103.4)	(3.5)	0.3	0.7	(105.9)	0.0	(105.9)	(104.8)
13	Services - plastic	(394.8)	(22.7)	1.9	7.7	(407.9)	0.0	(407.9)	(402.8)
14	Regulators	(32.7)	(4.3)	0.0	0.0	(37.0)	0.0	(37.0)	(34.8)
15	House regulators & meter installations	(26.2)	(2.0)	0.1	0.0	(28.1)	0.0	(28.1)	(27.1)
16	Mains - metallic	(339.1)	(14.9)	0.5	0.1	(353.4)	0.0	(353.4)	(346.5)
17	Mains - plastic	(256.2)	(15.1)	0.5	0.0	(270.7)	0.0	(270.7)	(263.7)
18	Measuring & regulating equipment	(18.5)	(1.6)	0.0	0.0	(20.1)	0.0	(20.1)	(19.3)
19	Meters	(92.8)	(13.1)	8.9	(0.0)	(97.1)	0.0	(97.1)	(96.5)
20	Regulatory Overheads	(29.6)	(6.8)	0.0	0.0	(36.4)	0.0	(36.4)	(33.0)
21	Subtotal	(1,333.5)	(87.1)	12.2	8.5	(1,399.9)	0.0	(1,399.9)	(1,370.3)
	Union Rate Zones Distribution Plant - Northern & Eastern Operations								
22	Land rights intangibles	(4.0)	(0.2)	0.0	0.0	(4.2)	0.0	(4.2)	(4.1)
23	Structures and improvements	(23.4)	(1.6)	0.0	0.0	(25.0)	0.0	(25.0)	(24.2)
24	Services - metallic	(72.8)	(3.5)	0.2	0.4	(75.7)	0.0	(75.7)	(74.4)
25	Services - plastic	(196.6)	(12.2)	1.0	0.2	(207.6)	0.0	(207.6)	(202.6)
26	Regulators	(11.9)	(1.8)	0.0	0.0	(13.6)	0.0	(13.6)	(12.7)
27	House regulators & meter installations	(14.2)	(1.2)	0.0	0.0	(15.3)	0.0	(15.3)	(14.7)
28	Mains - metallic	(312.6)	(17.8)	0.5	0.0	(329.9)	0.0	(329.9)	(321.4)

Utility Distribution Plant - EGI - Continuity of Accumulated Depreciation Year End Balances and Average of Monthly Averages (Continued)
2019 Actual

Line No.	Particulars ($ millions)	Dec. 2018 Opening Balance	Additions	Retirements	Costs Net of Proceeds	Dec. 2019 Closing Balance	Regulatory Adjustment	Dec. 2019 Utility Balance	Average of Monthly Averages
		(a)	(b)	(c)	(d)	(e) = (a+b+c+d)	(f)	(g) = (e+f)	(h)
29	Mains - plastic	(103.3)	(5.6)	0.2	0.0	(108.6)	0.0	(108.6)	(106.0)
30	Measuring & regulating equipment	(67.2)	(5.3)	0.6	0.0	(71.8)	0.0	(71.8)	(69.3)
31	Meters	(22.3)	(3.5)	2.6	0.0	(23.2)	0.0	(23.2)	(23.2)
32	Regulatory Overheads	(15.5)	(4.5)	0.0	0.0	(20.0)	0.0	(20.0)	(17.8)
33	Subtotal	(843.6)	(56.9)	5.0	0.6	(894.9)	0.0	(894.9)	(870.5)
34	EGI Total	(4,981.2)	(379.0)	86.8	51.8	(5,221.6)	2.9	(5,218.7)	(5,107.1)

Utility Transmission Plant - EGI - Continuity of Accumulated Depreciation Year End Balances and Average of Monthly Averages
2019 Actual

Line No.	Particulars ($ millions)	Dec. 2018 Opening Balance	Additions	Retirements	Costs Net of Proceeds	Dec. 2019 Closing Balance	Regulatory Adjustment	Dec. 2019 Utility Balance	Average of Monthly Averages
		(a)	(b)	(c)	(d)	(e) = (a+b+c+d)	(f)	(g) = (e+f)	(h)
	Union Rate Zones Transmission Plant								
1	Land rights	(15.8)	(1.1)	0.0	0.0	(16.9)	0.0	(16.9)	(16.4)
2	Structures & improvements	(36.8)	(3.4)	0.0	0.0	(40.1)	0.0	(40.1)	(38.4)
3	Mains	(593.8)	(35.6)	1.9	0.0	(627.4)	0.0	(627.4)	(611.4)
4	Compressor equipment	(233.2)	(30.3)	0.0	0.0	(263.5)	0.0	(263.5)	(248.3)
5	Measuring & regulating equipment	(89.2)	(7.2)	0.1	0.0	(96.3)	0.0	(96.3)	(92.7)
6	Regulatory Overheads	(13.9)	(4.1)	0.0	0.0	(18.1)	0.0	(18.1)	(15.9)
8	Total	(982.6)	(81.7)	2.0	0.0	(1,062.2)	0.0	(1,062.2)	(1,023.1)

Utility Storage Plant - EGI - Continuity of Accumulated Depreciation Year End Balances and Average of Monthly Averages
2019 Actual

Line No.	Particulars ($ millions)	Dec. 2018 Opening Balance	Additions	Retirements	Costs Net of Proceeds	Dec. 2019 Closing Balance	Regulatory Adjustment	Dec. 2019 Utility Balance	Average of Monthly Averages
		(a)	(b)	(c)	(d)	(e) = (a+b+c+d)	(f)	(g) = (e+f)	(h)
	EGD Rate Zone Underground Storage Plant								
1	Crowland storage	(1.3)	(0.1)	0.0	0.0	(1.4)	0.0	(1.4)	(1.3)
2	Land and gas storage rights	(24.7)	(0.5)	0.0	0.0	(25.2)	0.0	(25.2)	(25.0)
3	Structures and improvements	(2.8)	(0.6)	0.2	1.5	(1.7)	0.1	(1.6)	(2.1)
4	Wells	(14.7)	(0.9)	2.4	0.0	(13.3)	0.0	(13.3)	(13.3)
5	Well equipment	(7.4)	(0.6)	1.0	0.0	(7.0)	0.0	(7.0)	(6.9)
6	Field Lines	(29.8)	(1.6)	0.0	0.0	(31.3)	0.0	(31.3)	(30.5)
7	Compressor equipment	(50.1)	(3.6)	1.1	0.2	(52.4)	0.3	(52.1)	(50.9)
8	Measuring and regulating equipment	(7.3)	(0.3)	0.1	0.0	(7.5)	0.0	(7.5)	(7.4)
9	Subtotal	(138.0)	(8.1)	4.7	1.7	(139.7)	0.3	(139.4)	(137.4)
	Union Rate Zones Local Storage Plant								
10	Structures and improvements	(2.4)	(0.1)	0.0	0.0	(2.6)	0.0	(2.6)	(2.5)
11	Gas holders - storage	(3.6)	(0.1)	0.0	0.0	(3.7)	0.0	(3.7)	(3.6)
12	Gas holders - equipment	(8.9)	(0.7)	0.0	0.0	(9.6)	0.0	(9.6)	(9.2)
13	Regulatory Overheads	(0.3)	(0.1)	0.0	0.0	(0.4)	0.0	(0.4)	(0.4)
14	Subtotal	(15.2)	(1.1)	0.0	0.0	(16.3)	0.0	(16.3)	(15.8)
	Union Rate Zones Underground Storage Plant								
15	Land rights	(16.8)	(0.7)	0.0	0.0	(17.4)	0.0	(17.4)	(17.1)
16	Structures and improvements	(39.4)	(1.7)	0.7	0.0	(40.4)	0.0	(40.4)	(39.9)
17	Wells	(30.7)	(1.2)	0.0	0.0	(31.9)	0.0	(31.9)	(31.3)
18	Field Lines	(26.1)	(1.2)	0.0	0.0	(27.3)	0.0	(27.3)	(26.7)
19	Compressor equipment	(132.5)	(12.5)	0.0	0.0	(145.0)	0.0	(145.0)	(138.8)
20	Measuring & regulating equipment	(41.8)	(2.7)	2.8	0.0	(41.6)	0.0	(41.6)	(41.6)
21	Regulatory Overheads	(2.6)	(0.5)	0.0	0.0	(3.1)	0.0	(3.1)	(2.8)
22	Subtotal	(289.9)	(20.3)	3.4	0.0	(306.8)	0.0	(306.8)	(298.2)
23	EGI Total	(443.1)	(29.5)	8.1	1.7	(462.7)	0.3	(462.4)	(451.3)

Utility General Plant - EGI - Continuity of Accumulated Depreciation Year End Balances and Average of Monthly Averages
2019 Actual

Line No.	Particulars ($ millions)	Dec. 2018 Opening Balance	Additions	Retirements	Costs Net of Proceeds	Dec. 2019 Closing Balance	Regulatory Adjustment	Dec. 2019 Utility Balance	Average of Monthly Averages
		(a)	(b)	(c)	(d)	(e) = (a+b+c+d)	(f)	(g) = (e+f)	(h)
	EGD Rate Zone General Plant								
1	Lease improvements	(0.1)	(0.0)	0.0	0.0	(0.1)	0.2	0.1	0.1
2	Office furniture and equipment	(8.2)	(2.2)	0.0	0.0	(10.4)	0.0	(10.4)	(9.2)
3	Transportation equipment	(23.2)	(5.4)	2.5	(0.2)	(26.3)	0.1	(26.2)	(24.7)
4	NGV conversion kits	0.9	(0.2)	0.0	0.0	0.7	0.0	0.7	0.8
5	Heavy work equipment	(5.1)	(0.6)	0.6	(0.3)	(5.3)	0.0	(5.3)	(5.1)
6	Tools and work equipment	(17.9)	(2.1)	0.1	0.0	(19.9)	0.0	(19.9)	(18.9)
7	Rental equipment	(1.1)	(0.0)	0.0	0.0	(1.1)	0.0	(1.1)	(1.1)
8	NGV rental compressors	(0.6)	(0.6)	0.0	0.0	(1.3)	0.0	(1.3)	(1.0)
9	NGV cylinders	(0.5)	(0.0)	0.0	0.0	(0.6)	0.0	(0.6)	(0.5)
10	Communication structures & equip.	(1.1)	(0.4)	0.4	0.0	(1.1)	0.0	(1.1)	(1.3)
11	Computer equipment	(25.7)	(3.9)	0.7	0.0	(28.9)	0.0	(28.9)	(27.7)
12	Software Aquired/Developed	(188.8)	(36.9)	13.6	0.0	(212.1)	0.0	(212.1)	(202.5)
13	CIS	(117.6)	(9.5)	0.0	0.0	(127.1)	0.0	(127.1)	(123.5)
14	WAMS	(19.9)	(9.2)	0.0	0.0	(29.1)	0.0	(29.1)	(24.6)
15	Subtotal	(408.9)	(71.1)	17.9	(0.5)	(462.5)	0.3	(462.2)	(439.1)
	Union Rate Zones General Plant								
16	Structures & improvements	(13.2)	(1.5)	0.0	0.0	(14.7)	0.0	(14.7)	(13.9)
17	Office furniture and equipment	(5.0)	(0.7)	0.0	0.0	(5.7)	0.0	(5.7)	(5.4)
18	Office equipment - computers	(37.9)	(24.3)	0.0	0.0	(62.2)	0.0	(62.2)	(50.2)
19	Transportation equipment	(41.1)	(8.1)	5.4	(0.4)	(44.2)	0.0	(44.2)	(42.5)
20	Heavy work equipment	(4.6)	(1.1)	0.7	0.0	(5.0)	0.0	(5.0)	(4.8)
21	Tools and work equipment	(15.9)	(2.4)	0.0	0.0	(18.4)	0.0	(18.4)	(17.1)
22	NGV fuel equipment	(1.3)	(0.1)	0.0	0.0	(1.3)	0.0	(1.3)	(1.3)
23	Communication equipment	(7.5)	(1.0)	0.0	0.0	(8.4)	0.0	(8.4)	(8.0)
24	Regulatory Overheads	(19.9)	(5.2)	0.0	0.0	(25.1)	0.0	(25.1)	(22.5)
25	Subtotal	(146.3)	(44.3)	6.1	(0.4)	(184.9)	0.0	(184.9)	(165.6)
26	EGI Total	(555.1)	(115.4)	24.0	(0.8)	(647.4)	0.3	(647.1)	(604.7)

Utility Other Plant - EGI - Continuity of Accumulated Depreciation Year End Balances and Average of Monthly Averages
2019 Actual

Line No.	Particulars ($ millions)	Dec. 2018 Opening Balance	Additions	Retirements	Costs Net of Proceeds	Dec. 2019 Closing Balance	Regulatory Adjustment	Dec. 2019 Utility Balance	Average of Monthly Averages
		(a)	(b)	(c)	(d)	(e) = (a+b+c+d)	(f)	(g) = (e+f)	(h)
	EGD Rate Zone Plant held for future use								
1	Inactive services	(1.3)	(0.0)	0.0	0.0	(1.4)	0.0	(1.4)	(1.4)
	Union Rate Zones Intangible Plant								
2	Franchises and consents	(0.8)	(0.1)	0.0	0.0	(0.9)	0.0	(0.9)	(0.8)
3	Other intangible plant	(0.3)	0.0	0.0	0.0	(0.3)	0.0	(0.3)	(0.3)
4	Subtotal	(1.1)	(0.1)	0.0	0.0	(1.2)	0.0	(1.2)	(1.1)
5	EGI Total	(2.4)	(0.1)	0.0	0.0	(2.5)	0.0	(2.5)	(2.5)

Utility Gross Distribution Plant - EGI - Year End Balances and Average of Monthly Averages
2020 Actual

Line No.	Particulars ($ millions)	Dec. 2019 Opening Balance	Additions	Retirements	Dec. 2020 Closing Balance	Regulatory Adjustment	Dec. 2020 Utility Balance	Average of Monthly Averages
		(a)	(b)	(c)	(d) = (a +b+c)	(e)	(f) = (d+e)	(g)
	EGD Rate Zone Distribution Plant							
1	Renewable Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	Land	43.8	10.0	0.0	53.7	0.0	53.7	44.2
3	Offers to purchase	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	Land rights intangibles	63.8	0.0	0.0	63.8	0.0	63.8	63.8
5	Structures and improvements	146.0	5.0	(0.0)	151.0	(0.3)	150.7	146.1
6	Services, house reg & meter install.	3,091.2	223.0	(8.3)	3,306.0	0.0	3,306.0	3,187.5
7	Mains	4,692.0	144.5	(109.1)	4,727.4	(2.2)	4,725.2	4,637.5
8	NGV station compressors	4.5	1.0	0.0	5.5	0.0	5.5	4.9
9	Measuring and regulating equip.	629.8	58.1	(3.2)	684.7	(0.5)	684.2	644.2
10	Meters	497.6	22.1	0.0	519.6	0.0	519.6	481.0
11	Sub-total	9,168.6	463.7	(120.6)	9,511.7	(3.1)	9,508.6	9,209.1
	Union Rate Zones Distribution Plant - Southern Operations							
12	Land	11.8	0.8	0.0	12.6	0.0	12.6	12.1
13	Land rights	8.2	0.7	0.0	8.9	0.0	8.9	8.6
14	Structures and improvements	136.6	3.0	0.0	139.6	0.0	139.6	137.1
15	Services - metallic	126.0	2.4	0.0	128.4	0.0	128.4	126.7
16	Services - plastic	925.7	32.8	(1.7)	956.7	0.0	956.7	939.6
17	Regulators	91.1	6.0	0.0	97.1	0.0	97.1	95.4
18	House regulators & meter installations	73.5	3.5	0.0	76.9	0.0	76.9	74.1
19	Mains - metallic	557.3	25.9	(1.4)	581.8	0.0	581.8	555.7
20	Mains - plastic	674.1	32.9	(0.5)	706.4	0.0	706.4	684.0

Utility Gross Distribution Plant - EGI - Year End Balances and Average of Monthly Averages (Continued)
2020 Actual

Line No.	Particulars ($ millions)	Dec. 2019 Opening Balance	Additions	Retirements	Dec. 2020 Closing Balance	Regulatory Adjustment	Dec. 2020 Utility Balance	Average of Monthly Averages
		(a)	(b)	(c)	(d) = (a +b+c)	(e)	(f) = (d+e)	(g)
21	Measuring & regulating equipment	50.4	9.9	0.0	60.3	0.0	60.3	52.6
22	Meters	355.0	22.5	(4.2)	373.3	0.0	373.3	360.9
23	Regulatory Overheads	264.6	50.7	0.0	315.2	0.0	315.2	285.9
24	Sub-total	3,274.2	190.9	(7.9)	3,457.2	0.0	3,457.2	3,332.6
	Union Rate Zones Distribution Plant - Northern & Eastern Operations							
25	Land	4.6	0.3	0.0	5.0	0.0	5.0	4.8
26	Land rights	10.5	0.1	0.0	10.6	0.0	10.6	10.5
27	Structures and improvements	67.5	1.1	0.0	68.6	0.0	68.6	67.8
28	Services - metallic	108.5	1.6	(0.0)	110.1	0.0	110.1	109.4
29	Services - plastic	478.2	12.2	(0.8)	489.6	0.0	489.6	482.1
30	Regulators	41.4	(2.4)	0.0	39.0	0.0	39.0	39.8
31	House regulators & meter installations	40.9	0.6	0.0	41.5	0.0	41.5	41.2
32	Mains - metallic	625.4	55.4	(0.2)	680.5	0.0	680.5	645.0
33	Mains - plastic	238.3	0.5	(0.1)	238.7	0.0	238.7	239.0
34	Measuring & regulating equipment	145.9	5.4	0.0	151.3	0.0	151.3	146.6
35	Meters	88.8	9.5	(1.4)	96.8	0.0	96.8	92.5
36	Regulatory Overheads	168.7	4.4	0.0	173.1	0.0	173.1	170.3
37	Sub-total	2,018.7	88.7	(2.7)	2,104.7	0.0	2,104.7	2,049.0
38	EGI Total	14,461.5	743.3	(131.2)	15,073.6	(3.1)	15,070.6	14,590.7

Utility Transmission Plant - EGI - Year End Balances and Average of Monthly Averages
2020 Actual

Line No.	Particulars ($ millions)	Dec. 2019 Opening Balance	Additions	Retirements	Dec. 2020 Closing Balance	Regulatory Adjustment	Dec. 2020 Utility Balance	Average of Monthly Averages
		(a)	(b)	(c)	(d) = (a +b+c)	(e)	(f) = (d+e)	(g)
	Union Rate Zones Transmission Plant							
1	Land	75.4	10.3	(3.5)	82.2	0.0	82.2	74.2
2	Land rights	66.2	1.3	0.0	67.5	0.0	67.5	66.5
3	Structures & improvements	165.9	0.3	0.0	166.3	0.0	166.3	165.9
4	Mains	1,880.5	76.0	(1.9)	1,954.5	0.0	1,954.5	1,891.7
5	Compressor equipment	940.9	1.7	0.0	942.6	0.0	942.6	941.0
6	Measuring & regulating equipment	299.1	21.8	(0.0)	321.0	0.0	321.0	301.0
7	Line Pack Gas	7.5	0.0	0.0	7.5	0.0	7.5	7.5
8	Regulatory Overheads	176.8	23.3	0.0	200.1	0.0	200.1	189.0
9	Total	3,612.2	134.8	(5.5)	3,741.6	0.0	3,741.6	3,636.8

Utility Storage Plant - EGI - Year End Balances and Average of Monthly Averages
2020 Actual

Line No.	Particulars ($ millions)	Dec. 2019 Opening Balance	Additions	Retirements	Dec. 2020 Closing Balance	Regulatory Adjustment	Dec. 2020 Utility Balance	Average of Monthly Averages
		(a)	(b)	(c)	(d) = (a +b+c)	(e)	(f) = (d+e)	(g)
	EGD Rate Zone Underground Storage Plant							
1	Crowland storage	4.2	(0.0)	0.0	4.2	0.0	4.2	4.2
2	Land and gas storage rights	46.3	0.0	0.0	46.3	(1.0)	45.3	45.3
3	Structures and improvements	31.1	0.3	(0.0)	31.3	(0.1)	31.3	31.1
4	Wells	59.1	10.0	0.0	69.1	0.0	69.1	59.6
5	Well equipment	10.9	1.6	0.0	12.5	0.0	12.5	11.0
6	Field Lines	106.1	9.2	0.0	115.3	0.0	115.3	106.5
7	Compressor equipment	135.4	22.9	0.0	158.3	(0.5)	157.8	140.4
8	Measuring and regulating equipment	11.2	0.0	0.0	11.2	0.0	11.2	11.1
9	Base pressure gas	33.4	(0.0)	(1.1)	32.3	0.0	32.3	33.1
10	Sub-Total	437.6	43.9	(1.1)	480.4	(1.5)	478.9	442.2
	Union Rate Zones Local Storage Plant							
11	Land	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	Structures and improvements	4.7	0.5	0.0	5.2	0.0	5.2	4.8
13	Gas holders - storage	4.6	0.0	0.0	4.6	0.0	4.6	4.6
14	Gas holders - equipment	20.0	0.2	0.0	20.2	0.0	20.2	20.0
15	Regulatory Overheads	3.1	(1.3)	0.0	1.8	0.0	1.8	2.9
16	Sub-Total	32.4	(0.6)	0.0	31.8	0.0	31.8	32.3

Utility Storage Plant - EGI - Year End Balances and Average of Monthly Averages (Continued)
2020 Actual

Line No.	Particulars ($ millions)	Dec. 2019 Opening Balance	Additions	Retirements	Dec. 2020 Closing Balance	Regulatory Adjustment	Dec. 2020 Utility Balance	Average of Monthly Averages
		(a)	(b)	(c)	(d) = (a +b+c)	(e)	(f) = (d+e)	(g)
	Union Rate Zones Underground Storage Plant							
17	Land	5.6	1.7	0.0	7.2	0.0	7.2	5.6
18	Land rights	32.0	0.0	0.0	32.0	0.0	32.0	32.0
19	Structures and improvements	68.8	0.5	0.0	69.3	0.0	69.3	68.9
20	Wells	47.3	0.8	(0.1)	48.0	0.0	48.0	47.4
21	Field Lines	46.9	3.7	0.0	50.6	0.0	50.6	47.9
22	Compressor equipment	470.0	2.2	(2.1)	470.1	0.0	470.1	470.4
23	Measuring and regulating equipment	85.1	1.3	0.0	86.4	0.0	86.4	85.6
24	Base pressure gas	36.6	0.0	(0.4)	36.2	0.0	36.2	36.5
25	Regulatory Overheads	17.6	0.6	0.0	18.1	0.0	18.1	17.9
26	Sub-Total	809.7	10.7	(2.5)	817.9	0.0	817.9	812.3
27	EGI Total	1,279.8	54.1	(3.6)	1,330.2	(1.5)	1,328.7	1,286.8

Utility General Plant - EGI - Year End Balances and Average of Monthly Averages
2020 Actual

Line No.	Particulars ($ millions)	Dec. 2019 Opening Balance	Additions	Retirements	Dec. 2020 Closing Balance	Regulatory Adjustment	Dec. 2020 Utility Balance	Average of Monthly Averages
		(a)	(b)	(c)	(d) = (a +b+c)	(e)	(f) = (d+e)	(g)
	EGD Rate Zone General Plant							
1	Lease improvements	0.1	0.0	0.0	0.1	(0.2)	(0.1)	(0.1)
2	Office furniture and equipment	20.9	0.0	0.0	21.0	0.0	21.0	21.0
3	Transportation equipment	63.2	(0.9)	(0.6)	61.7	(0.1)	61.7	56.1
4	NGV conversion kits	2.5	0.5	0.0	2.9	0.0	2.9	2.8
5	Heavy work equipment	17.3	2.9	0.0	20.2	0.0	20.2	17.9
6	Tools and work equipment	50.9	8.4	(0.0)	59.3	0.0	59.3	56.6
7	Rental equipment	1.8	0.0	0.0	1.8	0.0	1.8	1.8
8	NGV rental compressors	7.4	12.8	0.0	20.2	0.0	20.2	13.4
9	NGV cylinders	0.6	0.3	0.0	1.0	0.0	1.0	0.9
10	Communication structures & equip.	3.7	(0.0)	0.0	3.7	0.0	3.7	3.7
11	Computer equipment	30.0	5.0	(3.0)	32.1	0.0	32.1	32.1
12	Software Aquired/Developed	235.0	34.6	(15.4)	254.3	0.0	254.3	232.4
13	CIS	127.1	0.0	0.0	127.1	0.0	127.1	127.1
14	WAMS	92.2	0.0	(0.1)	92.1	0.0	92.1	92.2
15	Sub-Total	652.7	63.7	(19.1)	697.4	(0.3)	697.1	657.9
	Union Rate Zones General Plant							
16	Land	0.6	0.0	0.0	0.6	0.0	0.6	0.5
17	Structures & improvements	73.0	1.1	(0.3)	73.8	0.0	73.8	73.3
18	Office furniture and equipment	10.1	0.0	0.0	10.1	0.0	10.1	10.1
19	Office equipment - computers	120.8	8.4	0.0	129.2	0.0	129.2	122.6
20	Transportation equipment	63.7	6.5	(5.5)	64.6	0.0	64.6	64.4
21	Heavy work equipment	19.3	1.1	(1.2)	19.2	0.0	19.2	21.0

Utility General Plant - EGI - Year End Balances and Average of Monthly Averages (Continued)
2020 Actual

Line No.	Particulars ($ millions)	Dec. 2019 Opening Balance	Additions	Retirements	Dec. 2020 Closing Balance	Regulatory Adjustment	Dec. 2020 Utility Balance	Average of Monthly Averages
		(a)	(b)	(c)	(d) = (a +b+c)	(e)	(f) = (d+e)	(g)
22	Tools and work equipment	37.2	2.0	0.0	39.2	0.0	39.2	37.7
23	NGV fuel equipment	2.0	1.2	0.0	3.2	0.0	3.2	2.6
24	Communication equipment	14.1	0.2	0.0	14.3	0.0	14.3	14.2
25	Regulatory Overheads	57.3	7.0	0.0	64.3	0.0	64.3	60.1
26	Sub-Total	398.1	27.5	(7.0)	418.6	0.0	418.6	406.5
27	EGI Total	1,050.8	91.2	(26.0)	1,115.9	(0.3)	1,115.7	1,064.4

Utility Other Plant -EGI - Year End Balances and Average of Monthly Averages
2020 Actual

Line No.	Particulars ($ millions)	Dec. 2019 Opening Balance	Additions	Retirements	Dec. 2020 Closing Balance	Regulatory Adjustment	Dec. 2020 Utility Balance	Average of Monthly Averages
		(a)	(b)	(c)	(d) = (a +b+c)	(e)	(f) = (d+e)	(g)
	EGD Rate Zone Plant held for future use							
1	Inactive services	1.7	0.0	0.0	1.7	0.0	1.7	1.7
	Union Rate Zones Intangible Plant							
2	Franchises and consents	1.2	0.0	0.0	1.2	0.0	1.2	1.2
3	Other intangible plant	0.5	0.0	0.0	0.5	0.0	0.5	0.5
4	Sub-Total	1.7	0.0	0.0	1.7	0.0	1.7	1.7
5	EGI Total	3.3	0.0	0.0	3.3	0.0	3.3	3.3

Utility Distribution Plant - EGI - Continuity of Accumulated Depreciation Year End Balances and Average of Monthly Averages
2020 Actual

Line No.	Particulars ($ millions)	Dec. 2019 Opening Balance (a)	Additions (b)	Retirements (c)	Costs Net of Proceeds (d)	Dec. 2020 Closing Balance (e) = (a+b+c+d)	Regulatory Adjustment (f)	Dec. 2020 Utility Balance (g) = (e+f)	Average of Monthly Averages (h)
	EGD Rate Zone Distribution Plant								
1	Renewable Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	Land rights intangibles	(5.0)	(0.8)	0.0	0.0	(5.7)	0.0	(5.7)	(5.4)
3	Structures and improvements	(34.0)	(9.0)	0.0	0.0	(42.9)	0.3	(42.6)	(38.4)
4	Services, house reg & meter install.	(1,065.6)	(73.4)	8.3	26.5	(1,104.3)	0.0	(1,104.3)	(1,085.5)
5	Mains	(1,314.1)	(100.8)	109.1	9.9	(1,295.9)	2.1	(1,293.8)	(1,271.9)
6	NGV station compressors	(3.0)	(0.3)	0.0	0.0	(3.3)	0.0	(3.3)	(3.1)
7	Measuring and regulating equip.	(243.1)	(13.0)	3.2	0.5	(252.4)	0.5	(251.9)	(247.5)
8	Meters	(262.1)	(41.3)	0.0	0.1	(303.2)	0.0	(303.2)	(281.8)
9	Sub-total	(2,926.8)	(238.5)	120.6	37.0	(3,007.7)	2.9	(3,004.8)	(2,933.5)
	Union Rate Zones Distribution Plant - Southern Operations								
10	Land rights	(2.1)	(0.1)	0.0	0.0	(2.3)	0.0	(2.3)	(2.2)
11	Structures and improvements	(41.3)	(3.0)	0.0	0.0	(44.3)	0.0	(44.3)	(42.8)
12	Services - metallic	(105.9)	(3.6)	(0.0)	2.2	(107.3)	0.0	(107.3)	(106.8)
13	Services - plastic	(407.9)	(23.6)	1.7	1.2	(428.6)	0.0	(428.6)	(421.2)
14	Regulators	(37.0)	(4.8)	0.0	0.0	(41.7)	0.0	(41.7)	(39.3)
15	House regulators & meter installations	(28.1)	(2.1)	0.0	0.0	(30.1)	0.0	(30.1)	(29.1)
16	Mains - metallic	(353.4)	(15.6)	1.4	4.0	(363.6)	0.0	(363.6)	(358.4)
17	Mains - plastic	(270.7)	(15.8)	0.6	0.6	(285.4)	0.0	(285.4)	(278.2)
18	Measuring & regulating equipment	(20.1)	(1.9)	0.0	0.5	(21.5)	0.0	(21.5)	(20.8)
19	Meters	(97.1)	(13.8)	4.2	(0.1)	(106.8)	0.0	(106.8)	(102.1)
20	Regulatory Overheads	(36.4)	(8.1)	0.0	0.0	(44.5)	0.0	(44.5)	(40.3)
21	Sub-Total	(1,399.9)	(92.3)	7.8	8.3	(1,476.0)	0.0	(1,476.0)	(1,441.1)
	Union Rate Zones Distribution Plant - Northern & Eastern Operations								
22	Land rights intangibles	(4.2)	(0.2)	0.0	0.0	(4.3)	0.0	(4.3)	(4.2)
23	Structures and improvements	(25.0)	(1.6)	0.0	0.0	(26.7)	0.0	(26.7)	(25.9)
24	Services - metallic	(75.7)	(3.5)	0.0	0.5	(78.6)	0.0	(78.6)	(77.4)
25	Services - plastic	(207.6)	(12.5)	0.8	0.3	(219.0)	0.0	(219.0)	(213.8)
26	Regulators	(13.6)	(2.0)	0.0	(0.0)	(15.6)	0.0	(15.6)	(14.6)
27	House regulators & meter installations	(15.3)	(1.2)	0.0	0.0	(16.5)	0.0	(16.5)	(15.9)
28	Mains - metallic	(329.9)	(19.3)	0.3	0.4	(348.4)	0.0	(348.4)	(339.2)

Utility Distribution Plant - EGI - Continuity of Accumulated Depreciation Year End Balances and Average of Monthly Averages (Continued)
2020 Actual

Line No.	Particulars ($ millions)	Dec. 2019 Opening Balance	Additions	Retirements	Costs Net of Proceeds	Dec. 2020 Closing Balance	Regulatory Adjustment	Dec. 2020 Utility Balance	Average of Monthly Averages
		(a)	(b)	(c)	(d)	(e) = (a+b+c+d)	(f)	(g) = (e+f)	(h)
29	Mains - plastic	(108.6)	(5.7)	0.1	0.0	(114.2)	0.0	(114.2)	(111.5)
30	Measuring & regulating equipment	(71.8)	(5.5)	0.0	0.0	(77.3)	0.0	(77.3)	(74.5)
31	Meters	(23.2)	(3.7)	1.4	(0.0)	(25.5)	0.0	(25.5)	(24.3)
32	Regulatory Overheads	(20.0)	(4.8)	0.0	0.0	(24.8)	0.0	(24.8)	(22.4)
33	Sub-Total	(894.9)	(60.0)	2.7	1.2	(950.9)	0.0	(950.9)	(923.8)
34	EGI Total	(5,221.6)	(390.8)	131.2	46.5	(5,434.7)	2.9	(5,431.7)	(5,298.4)

Utility Transmission Plant - EGI - Continuity of Accumulated Depreciation Year End Balances and Average of Monthly Averages
2020 Actual

Line No.	Particulars ($ millions)	Dec. 2019 Opening Balance	Additions	Retirements	Costs Net of Proceeds	Dec. 2020 Closing Balance	Regulatory Adjustment	Dec. 2020 Utility Balance	Average of Monthly Averages
		(a)	(b)	(c)	(d)	(e) = (a+b+c+d)	(f)	(g) = (e+f)	(h)
	Union Rate Zones Transmission Plant								
1	Land rights	(16.9)	(1.2)	0.0	0.0	(18.1)	0.0	(18.1)	(17.5)
2	Structures & improvements	(40.1)	(3.4)	0.0	0.0	(43.5)	0.0	(43.5)	(41.8)
3	Mains	(627.4)	(37.4)	1.9	0.0	(662.8)	0.0	(662.8)	(645.9)
4	Compressor equipment	(263.5)	(30.4)	0.0	0.0	(293.9)	0.0	(293.9)	(278.7)
5	Measuring & regulating equipment	(96.3)	(7.8)	0.0	0.0	(104.0)	0.0	(104.0)	(100.1)
6	Regulatory Overheads	(18.1)	(4.7)	0.0	0.0	(22.8)	0.0	(22.8)	(20.4)
8	Total	(1,062.2)	(84.8)	1.9	0.0	(1,145.1)	0.0	(1,145.1)	(1,104.4)

Utility Storage Plant - EGI - Continuity of Accumulated Depreciation Year End Balances and Average of Monthly Averages
2020 Actual

Line No.	Particulars ($ millions)	Dec. 2019 Opening Balance (a)	Additions (b)	Retirements (c)	Costs Net of Proceeds (d)	Dec. 2020 Closing Balance (e) = (a+b+c+d)	Regulatory Adjustment (f)	Dec. 2020 Utility Balance (g) = (e+f)	Average of Monthly Averages (h)
	EGD Rate Zone Underground Storage Plant								
1	Crowland storage	(1.4)	(0.0)	0.0	0.0	(1.4)	0.0	(1.4)	(1.4)
2	Land and gas storage rights	(25.2)	(0.5)	0.0	0.0	(25.7)	0.0	(25.7)	(25.5)
3	Structures and improvements	(1.7)	(0.6)	0.0	0.0	(2.2)	0.1	(2.2)	(1.9)
4	Wells	(13.3)	(1.0)	0.0	0.0	(14.2)	0.0	(14.2)	(13.7)
5	Well equipment	(7.0)	(0.6)	0.0	0.0	(7.6)	0.0	(7.6)	(7.3)
6	Field Lines	(31.3)	(1.6)	0.0	0.0	(32.9)	0.0	(32.9)	(32.1)
7	Compressor equipment	(52.4)	(4.3)	0.0	4.4	(52.3)	0.3	(52.0)	(53.4)
8	Measuring and regulating equipment	(7.5)	(0.3)	0.0	0.0	(7.9)	0.0	(7.9)	(7.7)
9	Sub-Total	(139.7)	(8.9)	0.0	4.4	(144.2)	0.3	(143.9)	(142.9)
	Union Rate Zones Local Storage Plant								
10	Structures and improvements	(2.6)	(0.1)	0.0	0.0	(2.7)	0.0	(2.7)	(2.6)
11	Gas holders - storage	(3.7)	(0.1)	0.0	0.0	(3.8)	0.0	(3.8)	(3.7)
12	Gas holders - equipment	(9.6)	(0.7)	0.0	0.0	(10.3)	0.0	(10.3)	(9.9)
13	Regulatory Overheads	(0.4)	(0.1)	0.0	0.0	(0.5)	0.0	(0.5)	(0.5)
14	Sub-Total	(16.3)	(1.1)	0.0	0.0	(17.3)	0.0	(17.3)	(16.8)
	Union Rate Zones Underground Storage Plant								
15	Land rights	(17.4)	(0.7)	0.0	0.0	(18.1)	0.0	(18.1)	(17.8)
16	Structures and improvements	(40.4)	(1.7)	0.0	0.0	(42.1)	0.0	(42.1)	(41.3)
17	Wells	(31.9)	(1.2)	0.1	0.0	(33.0)	0.0	(33.0)	(32.4)
18	Field Lines	(27.3)	(1.2)	0.0	0.0	(28.4)	0.0	(28.4)	(27.8)
19	Compressor equipment	(145.0)	(12.6)	2.1	0.0	(155.6)	0.0	(155.6)	(151.3)
20	Measuring & regulating equipment	(41.6)	(2.7)	0.0	0.0	(44.3)	0.0	(44.3)	(43.0)
21	Regulatory Overheads	(3.1)	(0.5)	0.0	0.0	(3.6)	0.0	(3.6)	(3.3)
22	Sub-Total	(306.7)	(20.5)	2.1	0.0	(325.1)	0.0	(325.1)	(316.8)
23	EGI Total	(462.7)	(30.5)	2.2	4.4	(486.6)	0.3	(486.3)	(476.6)

Utility General Plant - EGI - Continuity of Accumulated Depreciation Year End Balances and Average of Monthly Averages
2020 Actual

Line No.	Particulars ($ millions)	Dec. 2019 Opening Balance	Additions	Retirements	Costs Net of Proceeds	Dec. 2020 Closing Balance	Regulatory Adjustment	Dec. 2020 Utility Balance	Average of Monthly Averages
		(a)	(b)	(c)	(d)	(e) = (a+b+c+d)	(f)	(g) = (e+f)	(h)
	EGD Rate Zone General Plant								
1	Lease improvements	(0.1)	(0.0)	0.0	0.0	(0.1)	0.2	0.1	0.1
2	Office furniture and equipment	(10.4)	(2.2)	0.0	0.0	(12.6)	0.0	(12.6)	(11.5)
3	Transportation equipment	(26.3)	(6.5)	0.6	(0.0)	(32.2)	0.1	(32.2)	(29.0)
4	NGV conversion kits	0.7	(0.3)	0.0	0.0	0.4	0.0	0.4	0.6
5	Heavy work equipment	(5.3)	(0.7)	0.0	0.0	(6.0)	0.0	(6.0)	(5.7)
6	Tools and work equipment	(19.9)	(2.4)	0.0	(0.0)	(22.3)	0.0	(22.3)	(21.1)
7	Rental equipment	(1.1)	(0.0)	0.0	0.0	(1.1)	0.0	(1.1)	(1.1)
8	NGV rental compressors	(1.3)	(1.4)	0.0	0.0	(2.7)	0.0	(2.7)	(1.9)
9	NGV cylinders	(0.6)	0.0	0.0	0.0	(0.5)	0.0	(0.5)	(0.6)
10	Communication structures & equip.	(1.1)	(0.4)	0.0	0.0	(1.4)	0.0	(1.4)	(1.2)
11	Computer equipment	(28.9)	(5.8)	3.1	0.0	(31.6)	0.0	(31.6)	(31.8)
12	Software Aquired/Developed	(212.1)	(33.2)	15.4	0.0	(229.9)	0.0	(229.9)	(216.3)
13	CIS	(127.1)	0.0	0.0	0.0	(127.1)	0.0	(127.1)	(127.1)
14	WAMS	(29.1)	(9.2)	0.0	0.0	(38.3)	0.0	(38.3)	(33.8)
15	Sub-Total	(462.5)	(62.0)	19.1	(0.0)	(505.5)	0.3	(505.2)	(480.3)
	Union Rate Zones General Plant								
16	Structures & improvements	(14.7)	(1.5)	0.3	0.2	(15.7)	0.0	(15.7)	(15.2)
17	Office furniture and equipment	(5.7)	(0.7)	0.0	0.0	(6.4)	0.0	(6.4)	(6.0)
18	Office equipment - computers	(62.2)	(28.4)	0.0	0.0	(90.5)	0.0	(90.5)	(76.2)
19	Transportation equipment	(44.2)	(8.5)	5.5	(0.9)	(48.1)	0.0	(48.1)	(48.1)
20	Heavy work equipment	(5.0)	(1.5)	1.2	0.0	(5.3)	0.0	(5.3)	(5.6)
21	Tools and work equipment	(18.4)	(2.5)	0.0	0.0	(20.8)	0.0	(20.8)	(19.6)

Utility General Plant - EGI - Continuity of Accumulated Depreciation Year End Balances and Average of Monthly Averages (Continued)
2020 Actual

Line No.	Particulars ($ millions)	Dec. 2019 Opening Balance	Additions	Retirements	Costs Net of Proceeds	Dec. 2020 Closing Balance	Regulatory Adjustment	Dec. 2020 Utility Balance	Average of Monthly Averages
		(a)	(b)	(c)	(d)	(e) = (a+b+c+d)	(f)	(g) = (e+f)	(h)
22	NGV fuel equipment	(1.3)	(0.1)	0.0	0.0	(1.4)	0.0	(1.4)	(1.4)
23	Communication equipment	(8.4)	(0.9)	0.0	0.0	(9.4)	0.0	(9.4)	(8.9)
24	Regulatory Overheads	(25.1)	(5.9)	0.0	0.0	(31.0)	0.0	(31.0)	(28.0)
25	Sub-Total	(184.9)	(50.1)	7.0	(0.7)	(228.7)	0.0	(228.7)	(209.0)
26	EGI Total	(647.4)	(112.1)	26.0	(0.7)	(734.2)	0.3	(733.9)	(689.3)

Utility Other Plant - EGI - Continuity of Accumulated Depreciation Year End Balances and Average of Monthly Averages
2020 Actual

Line No.	Particulars ($ millions)	Dec. 2019 Opening Balance	Additions	Retirements	Costs Net of Proceeds	Dec. 2020 Closing Balance	Regulatory Adjustment	Dec. 2020 Utility Balance	Average of Monthly Averages
		(a)	(b)	(c)	(d)	(e) = (a+b+c+d)	(f)	(g) = (e+f)	(h)
	EGD Rate Zone Plant held for future use								
1	Inactive services	(1.4)	(0.0)	0.0	0.0	(1.4)	0.0	(1.4)	(1.4)
	Union Rate Zones Intangible Plant								
2	Franchises and consents	(0.9)	(0.1)	0.0	0.0	(0.9)	0.0	(0.9)	(0.9)
3	Other intangible plant	(0.3)	(0.0)	0.0	0.0	(0.3)	0.0	(0.3)	(0.3)
4	Sub-Total	(1.2)	(0.1)	0.0	0.0	(1.2)	0.0	(1.2)	(1.2)
5	EGI Total	(2.5)	(0.1)	0.0	0.0	(2.6)	0.0	(2.6)	(2.6)

Utility Gross Distribution Plant - EGI - Year End Balances and Average of Monthly Averages
2021 Actual

Line No.	Particulars ($ millions)	Dec. 2020 Opening Balance (a)	Additions (b)	Retirements (c)	Dec. 2021 Closing Balance (d) = (a+b+c)	Regulatory Adjustment (e)	Dec. 2021 Utility Balance (f) = (d+e)	Average of Monthly Averages (g)
	EGD Rate Zone Distribution Plant							
1	Renewable Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	Land	53.7	0.5	0.0	54.2	0.0	54.2	54.0
3	Offers to purchase	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	Land rights intangibles	63.8	0.0	0.0	63.8	0.0	63.8	63.8
5	Structures and improvements	151.0	49.7	(4.8)	196.0	(0.3)	195.6	157.6
6	Services, house reg & meter install.	3,306.0	204.9	(9.9)	3,501.0	0.0	3,501.0	3,372.2
7	Mains	4,727.4	158.0	73.5	4,958.8	(2.2)	4,956.6	4,780.5
8	NGV station compressors	5.5	(0.3)	0.0	5.2	0.0	5.2	5.2
9	Measuring and regulating equip.	684.7	22.6	(8.8)	698.5	(0.5)	698.0	693.5
10	Meters	519.6	29.0	(21.3)	527.3	0.0	527.3	516.5
11	Sub-total	9,511.7	464.4	28.8	10,004.8	(3.1)	10,001.8	9,643.2
	Union Rate Zones Distribution Plant - Southern Operations							
12	Land	12.6	4.1	0.0	16.7	0.0	16.7	15.3
13	Land rights	8.9	0.2	0.0	9.1	0.0	9.1	8.9
14	Structures and improvements	139.6	6.6	0.0	146.2	0.0	146.2	140.9
15	Services - metallic	128.4	2.4	(0.3)	130.5	0.0	130.5	129.2
16	Services - plastic	956.7	41.1	(1.8)	996.0	0.0	996.0	974.7
17	Regulators	97.1	13.4	(5.8)	104.8	0.0	104.8	102.6
18	House regulators & meter installations	76.9	10.3	0.0	87.2	0.0	87.2	78.1
19	Mains - metallic	581.8	103.5	(0.9)	684.3	0.0	684.3	598.0
20	Mains - plastic	706.4	44.4	(0.5)	750.3	0.0	750.3	721.0
21	Measuring & regulating equipment	60.3	13.1	0.0	73.4	0.0	73.4	61.4

Utility Gross Distribution Plant - EGI - Year End Balances and Average of Monthly Averages (Continued)
2021 Actual

Line No.	Particulars ($ millions)	Dec. 2020 Opening Balance	Additions	Retirements	Dec. 2021 Closing Balance	Regulatory Adjustment	Dec. 2021 Utility Balance	Average of Monthly Averages
		(a)	(b)	(c)	(d) = (a+b+c)	(e)	(f) = (d+e)	(g)
22	Meters	373.3	21.4	(3.3)	391.4	0.0	391.4	380.8
23	Regulatory Overheads	315.2	40.4	0.0	355.6	0.0	355.6	329.9
24	Sub-total	3,457.2	300.8	(12.7)	3,745.4	0.0	3,745.4	3,540.8
	Union Rate Zones Distribution Plant - Northern & Eastern Operations							
25	Land	5.0	0.3	0.0	5.3	0.0	5.3	5.2
26	Land rights	10.6	0.3	0.0	10.9	0.0	10.9	10.7
27	Structures and improvements	68.6	2.9	0.0	71.4	0.0	71.4	69.1
28	Services - metallic	110.1	1.4	(0.2)	111.2	0.0	111.2	110.5
29	Services - plastic	489.6	17.0	(0.8)	505.8	0.0	505.8	495.6
30	Regulators	39.0	0.8	(2.1)	37.7	0.0	37.7	39.2
31	House regulators & meter installations	41.5	0.7	0.0	42.3	0.0	42.3	41.7
32	Mains - metallic	680.5	40.2	(0.8)	719.9	0.0	719.9	688.0
33	Mains - plastic	238.7	7.9	(0.2)	246.3	0.0	246.3	240.5
34	Measuring & regulating equipment	151.3	4.2	0.0	155.5	0.0	155.5	152.2
35	Meters	96.8	6.3	(0.9)	102.2	0.0	102.2	97.3
36	Regulatory Overheads	173.1	32.5	0.0	205.6	0.0	205.6	184.5
37	Sub-total	2,104.7	114.4	(5.0)	2,214.1	0.0	2,214.1	2,134.6
38	EGI Total	15,073.6	879.6	11.1	15,964.3	(3.1)	15,961.2	15,318.6

Utility Transmission Plant - EGI - Year End Balances and Average of Monthly Averages
2021 Actual

Line No.	Particulars ($ millions)	Dec. 2020 Opening Balance	Additions	Retirements	Dec. 2021 Closing Balance	Regulatory Adjustment	Dec. 2021 Utility Balance	Average of Monthly Averages
		(a)	(b)	(c)	(d) = (a+b+c)	(e)	(f) = (d+e)	(g)
	Union Rate Zones Tansmission Plant							
1	Land	82.2	2.5	0.0	84.7	0.0	84.7	82.6
2	Land rights	67.5	0.9	0.0	68.3	0.0	68.3	67.6
3	Structures & improvements	166.3	0.8	0.0	167.1	0.0	167.1	166.3
4	Mains	1,954.5	61.9	(4.1)	2,012.3	0.0	2,012.3	1,963.6
5	Compressor equipment	942.6	3.0	0.0	945.7	0.0	945.7	943.4
6	Measuring & regulating equipment	321.0	45.0	0.0	366.0	0.0	366.0	325.7
7	Line Pack Gas	7.5	0.0	0.0	7.5	0.0	7.5	7.5
8	Regulatory Overheads	200.1	31.4	0.0	231.5	0.0	231.5	210.7
9	Total	3,741.6	145.5	(4.1)	3,883.1	0.0	3,883.1	3,767.4

Utility Storage Plant - EGI - Year End Balances and Average of Monthly Averages
2021 Actual

Line No.	Particulars ($ millions)	Dec. 2020 Opening Balance (a)	Additions (b)	Retirements (c)	Dec. 2021 Closing Balance (d) = (a+b+c)	Regulatory Adjustment (e)	Dec. 2021 Utility Balance (f) = (d+e)	Average of Monthly Averages (g)
	EGD Rate Zone Underground Storage Plant							
1	Land and gas storage rights	47.6	1.3	0.0	48.9	(1.0)	47.9	46.6
2	Structures and improvements	31.5	0.6	0.0	32.1	(0.1)	32.0	31.5
3	Wells	70.0	22.4	0.0	92.4	0.0	92.4	71.0
4	Well equipment	12.6	0.7	0.0	13.4	0.0	13.4	12.7
5	Field Lines	115.4	12.3	0.0	127.7	0.0	127.7	115.9
6	Compressor equipment	159.7	36.4	0.0	196.2	(0.5)	195.7	164.3
7	Measuring and regulating equipment	11.2	0.0	0.0	11.2	0.0	11.2	11.2
8	Base pressure gas	32.4	0.0	0.0	32.4	0.0	32.4	32.4
9	Sub-Total	480.5	73.8	0.0	554.3	(1.5)	552.7	485.6
	Union Rate Zones Local Storage Plant							
10	Land	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	Structures and improvements	5.2	0.7	0.0	5.9	0.0	5.9	5.2
12	Gas holders - storage	4.6	0.8	0.0	5.4	0.0	5.4	4.6
13	Gas holders - equipment	20.2	0.0	0.0	20.2	0.0	20.2	20.2
14	Regulatory Overheads	1.8	0.3	0.0	2.1	0.0	2.1	1.9
15	Sub-Total	31.8	1.8	0.0	33.6	0.0	33.6	32.0

Utility Storage Plant - EGI - Year End Balances and Average of Monthly Averages (Continued)
2021 Actual

Line No.	Particulars ($ millions)	Dec. 2020 Opening Balance	Additions	Retirements	Dec. 2021 Closing Balance	Regulatory Adjustment	Dec. 2021 Utility Balance	Average of Monthly Averages
		(a)	(b)	(c)	(d) = (a+b+c)	(e)	(f) = (d+e)	(g)
	Union Rate Zones Underground Storage Plant							
16	Land	7.2	2.4	0.0	9.6	0.0	9.6	7.3
17	Land rights	32.0	0.0	0.0	32.0	0.0	32.0	32.0
18	Structures and improvements	69.3	0.9	0.0	70.2	0.0	70.2	69.4
19	Wells	48.0	1.1	0.0	49.1	0.0	49.1	48.5
20	Field Lines	50.6	0.5	0.0	51.1	0.0	51.1	50.8
21	Compressor equipment	470.1	2.9	0.0	473.0	0.0	473.0	470.6
22	Measuring and regulating equipment	86.4	(23.6)	0.0	62.8	0.0	62.8	85.5
23	Base pressure gas	36.2	0.0	0.0	36.2	0.0	36.2	36.2
24	Regulatory Overheads	18.1	3.6	0.0	21.7	0.0	21.7	19.4
25	Sub-Total	817.9	(12.1)	0.0	805.8	0.0	805.8	819.7
26	EGI Total	1,330.2	63.5	0.0	1,393.7	(1.5)	1,392.2	1,337.3

Utility General Plant - EGI - Year End Balances and Average of Monthly Averages
2021 Actual

Line No.	Particulars ($ millions)	Dec. 2020 Opening Balance (a)	Additions (b)	Retirements (c)	Dec. 2021 Closing Balance (d) = (a+b+c)	Regulatory Adjustment (e)	Dec. 2021 Utility Balance (f) = (d+e)	Average of Monthly Averages (g)
	EGD Rate Zone General Plant							
1	Lease improvements	0.1	0.0	0.0	0.1	(0.2)	(0.1)	(0.1)
2	Office furniture and equipment	21.0	0.2	0.0	21.2	0.0	21.2	21.0
3	Transportation equipment	61.7	6.7	(1.4)	67.0	(0.1)	66.9	60.7
4	NGV conversion kits	2.9	0.0	0.0	2.9	0.0	2.9	2.9
5	Heavy work equipment	20.2	3.5	0.0	23.6	0.0	23.6	20.7
6	Tools and work equipment	59.3	2.0	0.0	61.3	0.0	61.3	59.7
7	Rental equipment	1.8	0.0	0.0	1.8	0.0	1.8	1.8
8	NGV rental compressors	20.2	(12.2)	0.0	8.0	0.0	8.0	19.7
9	NGV cylinders	1.0	(0.3)	0.0	0.6	0.0	0.6	0.7
10	Communication structures & equip.	3.7	0.0	(1.8)	1.8	0.0	1.8	2.7
11	Computer equipment	32.1	3.1	(7.4)	27.8	0.0	27.8	31.0
12	Software Aquired/Developed	254.3	9.6	(24.1)	239.8	0.0	239.8	248.8
13	CIS	127.1	14.1	(127.1)	14.1	0.0	14.1	114.0
14	WAMS	92.1	(0.1)	0.0	92.0	0.0	92.0	92.1
15	Sub-Total	697.4	26.7	(161.8)	562.3	(0.3)	562.0	675.7
	Union Rate Zones General Plant							
16	Land	0.5	0.0	0.0	0.5	0.0	0.5	0.5
17	Structures & improvements	73.8	16.1	0.0	90.0	0.0	90.0	78.3
18	Office furniture and equipment	10.1	0.0	(0.9)	9.3	0.0	9.3	10.0
19	Office equipment - computers	129.2	52.4	(68.3)	113.2	0.0	113.2	140.0
20	Transportation equipment	64.6	6.3	(5.1)	65.9	0.0	65.9	64.7
21	Heavy work equipment	19.2	2.3	(0.5)	21.0	0.0	21.0	19.3

Utility General Plant - EGI - Year End Balances and Average of Monthly Averages (Continued)
2021 Actual

Line No.	Particulars ($ millions)	Dec. 2020 Opening Balance	Additions	Retirements	Dec. 2021 Closing Balance	Regulatory Adjustment	Dec. 2021 Utility Balance	Average of Monthly Averages
		(a)	(b)	(c)	(d) = (a+b+c)	(e)	(f) = (d+e)	(g)
22	Tools and work equipment	39.2	2.2	(6.0)	35.4	0.0	35.4	38.8
23	NGV fuel equipment	3.2	1.3	0.0	4.5	0.0	4.5	3.3
24	Communication equipment	14.3	0.1	(4.9)	9.5	0.0	9.5	13.0
25	Regulatory Overheads	64.3	15.8	(9.8)	70.3	0.0	70.3	69.4
26	Sub-Total	418.6	96.5	(95.5)	419.6	0.0	419.6	437.5
27	EGI Total	1,115.9	123.1	(257.2)	981.8	(0.3)	981.6	1,113.1

Utility Other Plant -EGI - Year End Balances and Average of Monthly Averages
2021 Actual

Line No.	Particulars ($ millions)	Dec. 2020 Opening Balance	Additions	Retirements	Dec. 2021 Closing Balance	Regulatory Adjustment	Dec. 2021 Utility Balance	Average of Monthly Averages
		(a)	(b)	(c)	(d) = (a+b+c)	(e)	(f) = (d+e)	(g)
	EGD Rate Zone Plant held for future use							
1	Inactive services	1.7	0.0	0.0	1.7	0.0	1.7	1.7
	Union Rate Zones Intangible Plant							
2	Franchises and consents	1.2	0.0	0.0	1.2	0.0	1.2	1.2
3	Other intangible plant	0.5	0.0	0.0	0.5	0.0	0.5	0.5
4	Sub-Total	1.7	0.0	0.0	1.7	0.0	1.7	1.7
5	EGI Total	3.3	0.0	0.0	3.3	0.0	3.3	3.3

Utility Distribution Plant - EGI - Continuity of Accumulated Depreciation Year End Balances and Average of Monthly Averages
2021 Actual

Line No.	Particulars ($ millions)	Dec. 2020 Opening Balance (a)	Additions (b)	Retirements (c)	Costs Net of Proceeds (d)	Dec. 2021 Closing Balance (e) = (a+b+c+d)	Regulatory Adjustment (f)	Dec. 2021 Utility Balance (g) = (e+f)	Average of Monthly Averages (h)
	EGD Rate Zone Distribution Plant								
1	Renewable Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	Land rights intangibles	(5.7)	(0.8)	0.0	0.0	(6.5)	0.0	(6.5)	(6.1)
3	Structures and improvements	(42.9)	(11.1)	4.8	0.0	(49.2)	0.3	(48.9)	(43.4)
4	Services, house reg & meter install.	(1,104.3)	(76.4)	9.9	28.4	(1,142.4)	0.0	(1,142.4)	(1,126.2)
5	Mains	(1,295.9)	(109.4)	(73.5)	16.9	(1,461.9)	2.2	(1,459.7)	(1,322.2)
6	NGV station compressors	(3.3)	(0.3)	0.0	0.0	(3.6)	0.0	(3.6)	(3.4)
7	Measuring and regulating equip.	(252.4)	(15.1)	8.8	0.7	(257.9)	0.5	(257.4)	(254.4)
8	Meters	(303.2)	(41.0)	21.3	0.0	(323.0)	0.0	(323.0)	(315.7)
9	Sub-total	(3,007.7)	(254.0)	(28.8)	46.1	(3,244.4)	3.0	(3,241.4)	(3,071.5)
	Union Rate Zones Distribution Plant - Southern Operations								
10	Land rights	(2.3)	(0.1)	0.0	0.0	(2.4)	0.0	(2.4)	(2.3)
11	Structures and improvements	(44.3)	(3.1)	0.0	0.0	(47.4)	0.0	(47.4)	(45.8)
12	Services - metallic	(107.3)	(3.6)	0.3	1.8	(108.8)	0.0	(108.8)	(108.7)
13	Services - plastic	(428.6)	(24.5)	1.8	6.8	(444.5)	0.0	(444.5)	(437.2)
14	Regulators	(41.7)	(4.8)	5.8	0.0	(40.8)	0.0	(40.8)	(43.1)
15	House regulators & meter installations	(30.1)	(2.2)	0.0	0.0	(32.3)	0.0	(32.3)	(31.2)
16	Mains - metallic	(363.6)	(16.8)	0.9	3.6	(375.9)	0.0	(375.9)	(370.5)
17	Mains - plastic	(285.4)	(16.6)	0.5	0.5	(300.9)	0.0	(300.9)	(293.3)
18	Measuring & regulating equipment	(21.5)	(2.4)	0.0	0.3	(23.6)	0.0	(23.6)	(22.4)
19	Meters	(106.8)	(14.5)	3.3	(0.1)	(118.0)	0.0	(118.0)	(112.0)
20	Regulatory Overheads	(44.5)	(9.4)	0.0	0.0	(53.9)	0.0	(53.9)	(48.9)
21	Sub-Total	(1,476.1)	(98.1)	12.7	13.1	(1,548.5)	0.0	(1,548.5)	(1,515.5)
	Union Rate Zones Distribution Plant - Northern & Eastern Operations								
22	Land rights intangibles	(4.3)	(0.2)	0.0	0.0	(4.5)	0.0	(4.5)	(4.4)
23	Structures and improvements	(26.7)	(1.7)	0.0	0.0	(28.3)	0.0	(28.3)	(27.5)
24	Services - metallic	(78.6)	(3.6)	0.2	0.5	(81.4)	0.0	(81.4)	(80.2)
25	Services - plastic	(219.0)	(12.9)	0.8	0.4	(230.7)	0.0	(230.7)	(225.3)
26	Regulators	(15.6)	(1.8)	2.1	(0.0)	(15.3)	0.0	(15.3)	(16.1)
27	House regulators & meter installations	(16.5)	(1.2)	0.0	0.0	(17.7)	0.0	(17.7)	(17.1)
28	Mains - metallic	(348.4)	(20.7)	0.8	1.5	(366.9)	0.0	(366.9)	(358.3)

Utility Distribution Plant - EGI - Continuity of Accumulated Depreciation Year End Balances and Average of Monthly Averages (Continued)
2021 Actual

Line No.	Particulars ($ millions)	Dec. 2020 Opening Balance (a)	Additions (b)	Retirements (c)	Costs Net of Proceeds (d)	Dec. 2021 Closing Balance (e) = (a+b+c+d)	Regulatory Adjustment (f)	Dec. 2021 Utility Balance (g) = (e+f)	Average of Monthly Averages (h)
29	Mains - plastic	(114.2)	(5.7)	0.2	0.0	(119.6)	0.0	(119.6)	(117.0)
30	Measuring & regulating equipment	(77.3)	(5.7)	0.0	0.3	(82.7)	0.0	(82.7)	(80.0)
31	Meters	(25.5)	(3.9)	0.9	0.0	(28.6)	0.0	(28.6)	(26.9)
32	Regulatory Overheads	(24.8)	(5.2)	0.0	0.0	(30.0)	0.0	(30.0)	(27.3)
33	Sub-Total	(950.9)	(62.7)	5.0	2.7	(1,005.9)	0.0	(1,005.9)	(980.1)
34	EGI Total	(5,434.7)	(414.9)	(11.1)	61.8	(5,798.8)	3.0	(5,795.7)	(5,567.2)

Utility Transmission Plant - EGI - Continuity of Accumulated Depreciation Year End Balances and Average of Monthly Averages
2021 Actual

Line No.	Particulars ($ millions)	Dec. 2020 Opening Balance	Additions	Retirements	Costs Net of Proceeds	Dec. 2021 Closing Balance	Regulatory Adjustment	Dec. 2021 Utility Balance	Average of Monthly Averages
		(a)	(b)	(c)	(d)	(e) = (a+b+c+d)	(f)	(g) = (e+f)	(h)
	Union Rate Zones Tansmission Plant								
1	Land rights	(18.1)	(1.2)	0.0	0.0	(19.3)	0.0	(19.3)	(18.7)
2	Structures & improvements	(43.5)	(3.4)	0.0	0.1	(46.8)	0.0	(46.8)	(45.1)
3	Mains	(662.8)	(38.9)	4.1	0.4	(697.3)	0.0	(697.3)	(682.0)
4	Compressor equipment	(293.9)	(30.5)	0.0	0.0	(324.3)	0.0	(324.3)	(309.1)
5	Measuring & regulating equipment	(104.0)	(12.2)	0.0	0.0	(116.2)	0.0	(116.2)	(108.4)
6	Regulatory Overheads	(22.8)	(5.2)	0.0	0.0	(28.0)	0.0	(28.0)	(25.3)
8	Total	(1,145.1)	(91.4)	4.1	0.5	(1,231.9)	0.0	(1,231.9)	(1,188.6)

Utility Storage Plant - EGI - Continuity of Accumulated Depreciation Year End Balances and Average of Monthly Averages
2021 Actual

Line No.	Particulars ($ millions)	Dec. 2020 Opening Balance	Additions	Retirements	Costs Net of Proceeds	Dec. 2021 Closing Balance	Regulatory Adjustment	Dec. 2021 Utility Balance	Average of Monthly Averages
		(a)	(b)	(c)	(d)	(e) = (a+b+c+d)	(f)	(g) = (e+f)	(h)
	EGD Rate Zone Underground Storage Plant								
1	Land and gas storage rights	(26.6)	(0.5)	0.0	0.0	(27.1)	0.0	(27.1)	(26.8)
2	Structures and improvements	(2.3)	(0.6)	0.0	0.0	(2.9)	0.1	(2.8)	(2.5)
3	Wells	(14.3)	(1.2)	0.0	0.0	(15.5)	0.0	(15.5)	(14.8)
4	Well equipment	(7.8)	(0.8)	0.0	0.0	(8.6)	0.0	(8.6)	(8.1)
5	Field Lines	(32.2)	(1.8)	0.0	0.0	(34.0)	0.0	(34.0)	(33.1)
6	Compressor equipment	(53.2)	(4.5)	0.0	0.0	(57.7)	0.3	(57.4)	(55.0)
7	Measuring and regulating equipment	(7.9)	(0.3)	0.0	0.0	(8.3)	0.0	(8.3)	(8.1)
8	Sub-Total	(144.2)	(9.7)	0.0	0.0	(154.0)	0.3	(153.6)	(148.5)
	Union Rate Zones Local Storage Plant								
9	Structures and improvements	(2.7)	(0.1)	0.0	0.2	(2.7)	0.0	(2.7)	(2.7)
10	Gas holders - storage	(3.8)	(0.1)	0.0	0.0	(3.9)	0.0	(3.9)	(3.9)
11	Gas holders - equipment	(10.3)	(0.7)	0.0	0.0	(11.0)	0.0	(11.0)	(10.6)
12	Regulatory Overheads	(0.5)	(0.1)	0.0	0.0	(0.6)	0.0	(0.6)	(0.5)
13	Sub-Total	(17.3)	(1.0)	0.0	0.2	(18.2)	0.0	(18.2)	(17.8)
	Union Rate Zones Underground Storage Plant								
14	Land rights	(18.1)	(0.7)	0.0	0.0	(18.8)	0.0	(18.8)	(18.4)
15	Structures and improvements	(42.1)	(1.7)	0.0	0.0	(43.9)	0.0	(43.9)	(43.0)
16	Wells	(33.0)	(1.2)	0.0	0.0	(34.2)	0.0	(34.2)	(33.6)
17	Field Lines	(28.4)	(1.2)	0.0	0.0	(29.6)	0.0	(29.6)	(29.1)
18	Compressor equipment	(155.6)	(12.6)	0.0	0.0	(168.2)	0.0	(168.2)	(161.9)
19	Measuring & regulating equipment	(44.3)	1.2	0.0	0.1	(43.0)	0.0	(43.0)	(45.4)
20	Regulatory Overheads	(3.6)	(0.5)	0.0	0.0	(4.1)	0.0	(4.1)	(4.0)
21	Sub-Total	(325.1)	(16.7)	0.0	0.1	(341.7)	0.0	(341.7)	(335.4)
22	EGI Total	(486.6)	(27.5)	0.0	0.3	(513.9)	0.3	(513.5)	(501.6)

Utility General Plant - EGI - Continuity of Accumulated Depreciation Year End Balances and Average of Monthly Averages
2021 Actual

Line No.	Particulars ($ millions)	Dec. 2020 Opening Balance	Additions	Retirements	Costs Net of Proceeds	Dec. 2021 Closing Balance	Regulatory Adjustment	Dec. 2021 Utility Balance	Average of Monthly Averages
		(a)	(b)	(c)	(d)	(e) = (a+b+c+d)	(f)	(g) = (e+f)	(h)
	EGD Rate Zone General Plant								
1	Lease improvements	(0.1)	(0.0)	0.0	0.0	(0.1)	0.2	0.1	0.1
2	Office furniture and equipment	(12.6)	(2.2)	0.0	0.0	(14.8)	0.0	(14.8)	(13.7)
3	Transportation equipment	(32.2)	(6.2)	1.4	(0.1)	(37.2)	0.1	(37.1)	(34.3)
4	NGV conversion kits	0.4	(0.3)	0.0	0.0	0.2	0.0	0.2	0.3
5	Heavy work equipment	(6.0)	(0.7)	0.0	0.0	(6.8)	0.0	(6.8)	(6.4)
6	Tools and work equipment	(22.3)	(2.4)	0.0	0.0	(24.7)	0.0	(24.7)	(23.5)
7	Rental equipment	(1.1)	(0.0)	0.0	0.0	(1.1)	0.0	(1.1)	(1.1)
8	NGV rental compressors	(2.7)	0.2	0.0	0.0	(2.5)	0.0	(2.5)	(3.4)
9	NGV cylinders	(0.5)	(0.0)	0.0	0.0	(0.5)	0.0	(0.5)	(0.5)
10	Communication structures & equip.	(1.4)	(0.3)	1.8	0.0	0.1	0.0	0.1	(0.6)
11	Computer equipment	(31.6)	(2.7)	7.4	0.0	(27.0)	0.0	(27.0)	(30.5)
12	Software Aquired/Developed	(229.9)	(12.5)	24.1	0.0	(218.4)	0.0	(218.4)	(235.7)
13	CIS	(127.1)	(21.8)	127.1	0.0	(21.8)	0.0	(21.8)	(112.7)
14	WAMS	(38.4)	(9.2)	0.0	0.0	(47.6)	0.0	(47.6)	(43.0)
15	Sub-Total	(505.5)	(58.3)	161.8	(0.1)	(402.1)	0.3	(401.9)	(504.9)
	Union Rate Zones General Plant								
16	Structures & improvements	(15.7)	(1.6)	0.0	0.0	(17.3)	0.0	(17.3)	(16.5)
17	Office furniture and equipment	(6.4)	(0.6)	0.9	0.0	(6.2)	0.0	(6.2)	(6.6)
18	Office equipment - computers	(90.5)	(24.9)	68.3	0.0	(47.1)	0.0	(47.1)	(96.3)
19	Transportation equipment	(48.1)	(8.6)	5.1	(1.2)	(52.8)	0.0	(52.8)	(50.7)
20	Heavy work equipment	(5.3)	(1.3)	0.5	0.0	(6.2)	0.0	(6.2)	(5.8)
21	Tools and work equipment	(20.8)	(2.4)	6.0	0.0	(17.2)	0.0	(17.2)	(21.1)
22	NGV fuel equipment	(1.4)	(0.1)	0.0	0.0	(1.6)	0.0	(1.6)	(1.5)
23	Communication equipment	(9.4)	(0.7)	4.9	0.0	(5.2)	0.0	(5.2)	(8.5)
24	Regulatory Overheads	(31.0)	(6.3)	9.8	0.0	(27.5)	0.0	(27.5)	(33.9)
25	Sub-Total	(228.7)	(46.7)	95.5	(1.1)	(181.0)	0.0	(181.0)	(240.9)
26	EGI Total	(734.2)	(104.9)	257.2	(1.2)	(583.1)	0.3	(582.8)	(745.8)

Utility Other Plant - EGI - Continuity of Accumulated Depreciation Year End Balances and Average of Monthly Averages
2021 Actual

Line No.	Particulars ($ millions)	Dec. 2020 Opening Balance	Additions	Retirements	Costs Net of Proceeds	Dec. 2021 Closing Balance	Regulatory Adjustment	Dec. 2021 Utility Balance	Average of Monthly Averages
		(a)	(b)	(c)	(d)	(e) = (a+b+c+d)	(f)	(g) = (e+f)	(h)
	EGD Rate Zone Plant held for future use								
1	Inactive services	(1.4)	(0.0)	0.0	0.0	(1.4)	0.0	(1.4)	(1.4)
	Union Rate Zones Intangible Plant								
2	Franchises and consents	(0.9)	(0.1)	0.0	0.0	(1.0)	0.0	(1.0)	(1.0)
3	Other intangible plant	(0.3)	(0.2)	0.0	0.0	(0.5)	0.0	(0.5)	(0.3)
4	Sub-Total	(1.2)	(0.3)	0.0	0.0	(1.5)	0.0	(1.5)	(1.3)
5	EGI Total	(2.6)	(0.3)	0.0	0.0	(2.9)	0.0	(2.9)	(2.7)

Utility Gross Distribution Plant - EGI - Year End Balances and Average of Monthly Averages
2022 Estimate

Line No.	Particulars ($ millions)	Dec. 2021 Opening Balance	Additions	Retirements	Dec. 2022 Closing Balance	Regulatory Adjustment	Dec. 2022 Utility Balance	Average of Monthly Averages
		(a)	(b)	(c)	(d) = (a+b+c)	(e)	(f) = (d+e)	(g)
	EGD Rate Zone Distribution Plant							
1	Renewable Natural Gas	0.0	12.1	0.0	12.1	0.0	12.1	4.6
2	Land	54.2	38.6	(0.1)	92.7	0.0	92.7	86.5
3	Offers to purchase	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	Land rights intangibles	63.8	0.9	0.0	64.7	0.0	64.7	64.1
5	Structures and improvements	196.0	40.8	(1.0)	235.8	(0.3)	235.5	210.8
6	Services, house reg & meter install.	3,501.0	152.9	(8.6)	3,645.3	0.0	3,645.3	3,557.2
7	Mains	4,958.8	381.1	(20.8)	5,319.1	(2.2)	5,316.9	5,091.7
8	NGV station compressors	5.2	0.1	(0.1)	5.2	0.0	5.2	5.2
9	Measuring and regulating equip.	698.5	17.5	(1.5)	714.5	(0.5)	714.0	705.7
10	Meters	527.3	34.8	(13.5)	548.6	0.0	548.6	535.1
11	Sub-total	10,004.8	678.8	(45.6)	10,638.0	(3.1)	10,635.0	10,261.1
	Union Rate Zones Distribution Plant - Southern Operations							
12	Land	16.7	1.5	(0.0)	18.2	0.0	18.2	17.1
13	Land rights	9.1	0.2	0.0	9.2	0.0	9.2	9.1
14	Structures and improvements	146.2	9.7	(0.6)	155.3	0.0	155.3	147.5
15	Services - metallic	130.5	3.0	(0.4)	133.1	0.0	133.1	131.3
16	Services - plastic	996.0	35.6	(1.1)	1,030.4	0.0	1,030.4	1,005.6
17	Regulators	104.8	9.0	(1.8)	111.9	0.0	111.9	106.7
18	House regulators & meter installations	87.2	4.7	(1.0)	91.0	0.0	91.0	88.1
19	Mains - metallic	684.3	45.6	(1.2)	728.7	0.0	728.7	694.7
20	Mains - plastic	750.3	41.8	(0.2)	791.8	0.0	791.8	760.1
21	Measuring & regulating equipment	73.4	4.6	(0.3)	77.7	0.0	77.7	74.3

Utility Gross Distribution Plant - EGI - Year End Balances and Average of Monthly Averages (Continued)
2022 Estimate

Line No.	Particulars ($ millions)	Dec. 2021 Opening Balance	Additions	Retirements	Dec. 2022 Closing Balance	Regulatory Adjustment	Dec. 2022 Utility Balance	Average of Monthly Averages
		(a)	(b)	(c)	(d) = (a+b+c)	(e)	(f) = (d+e)	(g)
22	Meters	391.4	37.9	(7.4)	422.0	0.0	422.0	398.7
23	Regulatory Overheads	355.6	39.2	0.0	394.9	0.0	394.9	364.5
24	Sub-total	3,745.4	232.7	(13.9)	3,964.2	0.0	3,964.2	3,797.6
	Union Rate Zones Distribution Plant - Northern & Eastern Operations							
25	Land	5.3	0.5	(0.0)	5.7	0.0	5.7	5.4
26	Land rights	10.9	0.2	0.0	11.1	0.0	11.1	11.0
27	Structures and improvements	71.4	5.2	(0.3)	76.3	0.0	76.3	72.5
28	Services - metallic	111.2	2.6	(0.3)	113.5	0.0	113.5	111.8
29	Services - plastic	505.8	16.9	(0.6)	522.1	0.0	522.1	509.7
30	Regulators	37.7	3.2	(0.7)	40.2	0.0	40.2	38.3
31	House regulators & meter installations	42.3	2.1	(0.4)	44.0	0.0	44.0	42.7
32	Mains - metallic	719.9	42.9	(0.6)	762.2	0.0	762.2	729.3
33	Mains - plastic	246.3	14.5	(0.1)	260.8	0.0	260.8	249.6
34	Measuring & regulating equipment	155.5	10.9	(0.5)	166.0	0.0	166.0	157.9
35	Meters	102.2	9.8	(1.9)	110.1	0.0	110.1	104.1
36	Regulatory Overheads	205.6	22.8	0.0	228.3	0.0	228.3	210.7
37	Sub-total	2,214.1	131.7	(5.4)	2,340.4	0.0	2,340.4	2,243.1
38	EGI Total	15,964.3	1,043.2	(64.9)	16,942.6	(3.1)	16,939.5	16,301.8

Utility Transmission Plant - EGI - Year End Balances and Average of Monthly Averages
2022 Estimate

Line No.	Particulars ($ millions)	Dec. 2021 Opening Balance	Additions	Retirements	Dec. 2022 Closing Balance	Regulatory Adjustment	Dec. 2022 Utility Balance	Average of Monthly Averages
		(a)	(b)	(c)	(d) = (a+b+c)	(e)	(f) = (d+e)	(g)
	Union Rate Zones Transmission Plant							
1	Land	84.7	0.4	0.0	85.1	0.0	85.1	84.8
2	Land rights	68.3	0.2	0.0	68.5	0.0	68.5	68.4
3	Structures & improvements	167.1	1.3	(0.6)	167.8	0.0	167.8	167.2
4	Mains	2,012.3	52.7	(3.5)	2,061.5	0.0	2,061.5	2,022.8
5	Compressor equipment	945.7	5.8	(0.8)	950.7	0.0	950.7	946.6
6	Measuring & regulating equipment	366.0	53.1	(0.2)	418.9	0.0	418.9	378.1
7	Line Pack Gas	7.5	0.0	0.0	7.5	0.0	7.5	7.5
8	Regulatory Overheads	231.5	42.6	0.0	274.1	0.0	274.1	241.2
9	Total	3,883.1	156.1	(5.1)	4,034.0	0.0	4,034.0	3,916.6

Utility Storage Plant - EGI - Year End Balances and Average of Monthly Averages
2022 Estimate

Line No.	Particulars ($ millions)	Dec. 2021 Opening Balance	Additions	Retirements	Dec. 2022 Closing Balance	Regulatory Adjustment	Dec. 2022 Utility Balance	Average of Monthly Averages
		(a)	(b)	(c)	(d) = (a+b+c)	(e)	(f) = (d+e)	(g)
	EGD Rate Zone Underground Storage Plant							
1	Land and gas storage rights	48.9	0.5	0.0	49.5	(1.0)	48.4	48.1
2	Structures and improvements	32.1	0.4	(0.2)	32.3	(0.1)	32.2	32.1
3	Wells	92.4	7.0	(0.9)	98.5	0.0	98.5	94.8
4	Well equipment	13.4	2.5	(0.4)	15.5	0.0	15.5	14.2
5	Field Lines	127.7	12.9	(0.1)	140.5	0.0	140.5	133.2
6	Compressor equipment	196.2	15.7	(0.5)	211.4	(0.5)	210.9	202.0
7	Measuring and regulating equipment	11.2	0.0	(0.0)	11.2	0.0	11.2	11.2
8	Base pressure gas	32.4	0.0	0.0	32.4	0.0	32.4	32.4
9	Sub-Total	554.3	39.1	(2.2)	591.2	(1.5)	589.6	568.0
	Union Rate Zones Local Storage Plant							
10	Land	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	Structures and improvements	5.9	0.4	0.0	6.2	0.0	6.2	5.9
12	Gas holders - storage	5.4	0.4	0.0	5.9	0.0	5.9	5.5
13	Gas holders - equipment	20.2	0.0	0.0	20.2	0.0	20.2	20.2
14	Regulatory Overheads	2.1	2.2	0.0	4.3	0.0	4.3	2.6
15	Sub-Total	33.6	3.0	0.0	36.7	0.0	36.7	34.3

Utility Storage Plant - EGI - Year End Balances and Average of Monthly Averages (Continued)
2022 Estimate

Line No.	Particulars ($ millions)	Dec. 2021 Opening Balance	Additions	Retirements	Dec. 2022 Closing Balance	Regulatory Adjustment	Dec. 2022 Utility Balance	Average of Monthly Averages
		(a)	(b)	(c)	(d) = (a+b+c)	(e)	(f) = (d+e)	(g)
	Union Rate Zones Underground Storage Plant							
16	Land	9.6	0.0	(0.0)	9.6	0.0	9.6	9.6
17	Land rights	32.0	1.8	0.0	33.7	0.0	33.7	32.4
18	Structures and improvements	70.2	3.2	(0.7)	72.7	0.0	72.7	70.8
19	Wells	49.1	2.4	0.0	51.5	0.0	51.5	49.7
20	Field Lines	51.1	1.5	(0.5)	52.1	0.0	52.1	51.3
21	Compressor equipment	473.0	5.7	(7.3)	471.4	0.0	471.4	472.5
22	Measuring and regulating equipment	62.8	10.6	(1.1)	72.3	0.0	72.3	64.9
23	Base pressure gas	36.2	1.1	0.0	37.3	0.0	37.3	36.4
24	Regulatory Overheads	21.7	1.8	0.0	23.6	0.0	23.6	22.2
25	Sub-Total	805.8	28.1	(9.6)	824.3	0.0	824.3	809.8
26	EGI Total	1,393.7	70.2	(11.8)	1,452.2	(1.5)	1,450.6	1,412.1

Utility General Plant - EGI - Year End Balances and Average of Monthly Averages
2022 Estimate

Line No.	Particulars ($ millions)	Dec. 2021 Opening Balance	Additions	Retirements	Dec. 2022 Closing Balance	Regulatory Adjustment	Dec. 2022 Utility Balance	Average of Monthly Averages
		(a)	(b)	(c)	(d) = (a+b+c)	(e)	(f) = (d+e)	(g)
	EGD Rate Zone General Plant							
1	Investment in leased assets	10.4	15.9	0.0	26.3	0.0	26.3	16.5
2	Lease improvements	0.1	0.0	0.0	0.1	(0.2)	(0.1)	(0.1)
3	Office furniture and equipment	21.2	0.4	(0.4)	21.2	0.0	21.2	21.2
4	Transportation equipment	67.0	8.4	(2.6)	72.8	(0.1)	72.7	69.1
5	NGV conversion kits	2.9	0.2	(0.1)	3.0	0.0	3.0	3.0
6	Heavy work equipment	23.6	3.8	(0.5)	27.0	0.0	27.0	24.9
7	Tools and work equipment	61.3	7.5	(0.4)	68.4	0.0	68.4	64.4
8	Rental equipment	1.8	(0.0)	0.0	1.8	0.0	1.8	1.8
9	NGV rental compressors	8.0	0.0	(0.4)	7.5	0.0	7.5	7.8
10	NGV cylinders	0.6	0.0	0.0	0.6	0.0	0.6	0.6
11	Communication structures & equip.	1.8	0.0	(0.2)	1.6	0.0	1.6	1.8
12	Computer equipment	27.8	5.8	(3.7)	29.9	0.0	29.9	28.6
13	Software Aquired/Developed	239.8	52.4	(14.1)	278.1	0.0	278.1	255.6
14	CIS	14.1	(2.0)	0.0	12.2	0.0	12.2	12.2
15	WAMS	92.0	0.0	0.0	92.0	0.0	92.0	92.0
16	Sub-Total	572.7	92.4	(22.5)	642.6	(0.3)	642.3	599.5
	Union Rate Zones General Plant							
17	Land	0.5	0.0	0.0	0.5	0.0	0.5	0.5
18	Structures & improvements	90.0	10.8	(0.4)	100.4	0.0	100.4	92.3
19	Office furniture and equipment	9.3	0.4	(0.2)	9.5	0.0	9.5	9.3
20	Office equipment - computers	113.2	25.6	(11.3)	127.6	0.0	127.6	116.5
21	Transportation equipment	65.9	7.7	(3.9)	69.6	0.0	69.6	66.7

Utility General Plant - EGI - Year End Balances and Average of Monthly Averages
2022 Estimate

Line No.	Particulars ($ millions)	Dec. 2021 Opening Balance	Additions	Retirements	Dec. 2022 Closing Balance	Regulatory Adjustment	Dec. 2022 Utility Balance	Average of Monthly Averages
		(a)	(b)	(c)	(d) = (a+b+c)	(e)	(f) = (d+e)	(g)
22	Heavy work equipment	21.0	0.9	(0.4)	21.5	0.0	21.5	21.1
23	Tools and work equipment	35.4	4.0	(1.3)	38.1	0.0	38.1	36.0
24	NGV fuel equipment	4.5	0.7	0.0	5.2	0.0	5.2	4.7
25	Communication equipment	9.5	0.5	(0.2)	9.8	0.0	9.8	9.5
26	Regulatory Overheads	70.3	12.8	0.0	83.1	0.0	83.1	73.2
27	Sub-Total	419.6	63.4	(17.6)	465.3	0.0	465.3	430.0
28	EGI Total	992.3	155.7	(40.1)	1,107.9	(0.3)	1,107.6	1,029.5

Utility Other Plant -EGI - Year End Balances and Average of Monthly Averages
2022 Estimate

Line No.	Particulars ($ millions)	Dec. 2021 Opening Balance	Additions	Retirements	Dec. 2022 Closing Balance	Regulatory Adjustment	Dec. 2022 Utility Balance	Average of Monthly Averages
		(a)	(b)	(c)	(d) = (a+b+c)	(e)	(f) = (d+e)	(g)
	EGD Rate Zone Plant held for future use							
1	Inactive services	1.7	0.0	0.0	1.7	0.0	1.7	1.7
	Union Rate Zones Intangible Plant							
2	Franchises and consents	1.2	0.0	(0.0)	1.2	0.0	1.2	1.2
3	Other intangible plant	0.5	0.0	0.0	0.5	0.0	0.5	0.5
4	Sub-Total	1.7	0.0	(0.0)	1.7	0.0	1.7	1.7
5	EGI Total	3.3	0.0	(0.0)	3.3	0.0	3.3	3.3

Utility Distribution Plant - EGI - Continuity of Accumulated Depreciation Year End Balances and Average of Monthly Averages
2022 Estimate

Line No.	Particulars ($ millions)	Dec. 2021 Opening Balance	Additions	Retirements	Costs Net of Proceeds	Dec. 2022 Closing Balance	Regulatory Adjustment	Dec. 2022 Utility Balance	Average of Monthly Averages	
		(a)	(b)	(c)	(d)	(e) = (a+b+c+d)	(f)	(g) = (e+f)	(h)	
	EGD Rate Zone Distribution Plant									
1	Renewable Natural Gas	0.0	(0.3)	0.0	0.0	(0.3)	0.0	(0.3)	(0.1)	
2	Land rights intangibles	(6.5)	(0.8)	0.0	0.0	(7.3)	0.0	(7.3)	(6.9)	
3	Structures and improvements	(49.2)	(7.2)	1.0	2.5	(52.8)	0.3	(52.5)	(54.1)	
4	Services, house reg & meter install.	(1,142.4)	(80.3)	8.6	27.1	(1,186.9)	0.0	(1,186.9)	(1,167.5)	
5	Mains	(1,461.9)	(132.6)	20.8	14.3	(1,559.3)	2.2	(1,557.1)	(1,520.5)	/u
6	NGV station compressors	(3.6)	(0.3)	0.1	0.0	(3.8)	0.0	(3.8)	(3.7)	
7	Measuring and regulating equip.	(257.9)	(14.5)	1.5	1.1	(269.8)	0.5	(269.2)	(263.4)	
8	Meters	(323.0)	(49.0)	13.5	0.1	(358.3)	0.0	(358.3)	(341.4)	
9	Sub-total	(3,244.4)	(284.8)	45.5	45.2	(3,438.5)	3.1	(3,435.4)	(3,357.5)	/u
	Union Rate Zones Distribution Plant - Southern Operations									
10	Land rights	(2.4)	(0.2)	0.0	0.0	(2.6)	0.0	(2.6)	(2.5)	
11	Structures and improvements	(47.4)	(3.3)	0.6	0.0	(50.1)	0.0	(50.1)	(48.9)	
12	Services - metallic	(108.8)	(3.7)	0.4	7.3	(104.8)	0.0	(104.8)	(108.5)	
13	Services - plastic	(444.5)	(25.4)	1.1	7.7	(461.1)	0.0	(461.1)	(456.1)	
14	Regulators	(40.8)	(5.3)	1.8	0.0	(44.2)	0.0	(44.2)	(43.0)	
15	House regulators & meter installations	(32.3)	(2.5)	1.0	0.1	(33.7)	0.0	(33.7)	(33.2)	
16	Mains - metallic	(375.9)	(19.0)	1.2	4.5	(389.2)	0.0	(389.2)	(383.3)	
17	Mains - plastic	(300.9)	(17.7)	0.2	0.8	(317.6)	0.0	(317.6)	(309.5)	
18	Measuring & regulating equipment	(23.6)	(2.5)	0.3	0.2	(25.6)	0.0	(25.6)	(24.7)	
19	Meters	(118.0)	(15.6)	7.4	(0.4)	(126.7)	0.0	(126.7)	(124.0)	
20	Regulatory Overheads	(53.9)	(4.9)	0.0	0.0	(58.8)	0.0	(58.8)	(56.5)	
21	Sub-Total	(1,548.5)	(100.0)	13.9	20.2	(1,614.4)	0.0	(1,614.4)	(1,590.2)	
	Union Rate Zones Distribution Plant - Northern & Eastern Operations									
22	Land rights intangibles	(4.5)	(0.2)	0.0	0.0	(4.7)	0.0	(4.7)	(4.6)	
23	Structures and improvements	(28.3)	(1.8)	0.3	0.0	(29.8)	0.0	(29.8)	(29.1)	
24	Services - metallic	(81.4)	(3.6)	0.3	5.1	(79.7)	0.0	(79.7)	(82.0)	
25	Services - plastic	(230.7)	(13.4)	0.6	4.5	(239.0)	0.0	(239.0)	(236.2)	
26	Regulators	(15.3)	(2.0)	0.7	0.0	(16.7)	0.0	(16.7)	(16.2)	
27	House regulators & meter installations	(17.7)	(1.3)	0.4	0.1	(18.5)	0.0	(18.5)	(18.2)	
28	Mains - metallic	(366.9)	(22.8)	0.6	3.5	(385.5)	0.0	(385.5)	(377.2)	

Utility Distribution Plant - EGI - Continuity of Accumulated Depreciation Year End Balances and Average of Monthly Averages (Continued)
2022 Estimate

Line No.	Particulars ($ millions)	Dec. 2021 Opening Balance	Additions	Retirements	Costs Net of Proceeds	Dec. 2022 Closing Balance	Regulatory Adjustment	Dec. 2022 Utility Balance	Average of Monthly Averages	
		(a)	(b)	(c)	(d)	(e) = (a+b+c+d)	(f)	(g) = (e+f)	(h)	
29	Mains - plastic	(119.6)	(6.0)	0.1	0.3	(125.3)	0.0	(125.3)	(122.5)	
30	Measuring & regulating equipment	(82.7)	(6.1)	0.5	0.7	(87.6)	0.0	(87.6)	(85.5)	
31	Meters	(28.6)	(4.1)	1.9	(0.1)	(30.9)	0.0	(30.9)	(30.2)	
32	Regulatory Overheads+C17	(30.0)	(11.6)	0.0	0.0	(41.6)	0.0	(41.6)	(35.5)	
33	Sub-Total	(1,005.9)	(72.9)	5.4	14.1	(1,059.3)	0.0	(1,059.3)	(1,037.3)	
34	EGI Total	(5,798.8)	(457.8)	64.9	79.5	(6,112.1)	3.1	(6,109.1)	(5,985.0)	/u

Utility Transmission Plant - EGI - Continuity of Accumulated Depreciation Year End Balances and Average of Monthly Averages
2022 Estimate

Line No.	Particulars ($ millions)	Dec. 2021 Opening Balance	Additions	Retirements	Costs Net of Proceeds	Dec. 2022 Closing Balance	Regulatory Adjustment	Dec. 2022 Utility Balance	Average of Monthly Averages
		(a)	(b)	(c)	(d)	(e) = (a+b+c+d)	(f)	(g) = (e+f)	(h)
	Union Rate Zones Transmission Plant								
1	Land rights	(19.3)	(1.2)	0.0	0.0	(20.5)	0.0	(20.5)	(19.9)
2	Structures & improvements	(46.8)	(3.4)	0.6	0.0	(49.6)	0.0	(49.6)	(48.3)
3	Mains	(697.3)	(40.1)	3.5	0.0	(733.9)	0.0	(733.9)	(716.5)
4	Compressor equipment	(324.3)	(30.6)	0.8	0.0	(354.1)	0.0	(354.1)	(339.4)
5	Measuring & regulating equipment	(116.2)	(9.9)	0.2	0.0	(125.9)	0.0	(125.9)	(121.0)
6	Regulatory Overheads	(28.0)	(6.1)	0.0	0.0	(34.1)	0.0	(34.1)	(31.0)
8	Total	(1,231.9)	(91.2)	5.1	0.0	(1,318.0)	0.0	(1,318.0)	(1,276.1)

Utility Storage Plant - EGI - Continuity of Accumulated Depreciation Year End Balances and Average of Monthly Averages
2022 Estimate

Line No.	Particulars ($ millions)	Dec. 2021 Opening Balance	Additions	Retirements	Costs Net of Proceeds	Dec. 2022 Closing Balance	Regulatory Adjustment	Dec. 2022 Utility Balance	Average of Monthly Averages
		(a)	(b)	(c)	(d)	(e) = (a+b+c+d)	(f)	(g) = (e+f)	(h)
	EGD Rate Zone Underground Storage Plant								
1	Land and gas storage rights	(27.1)	(0.5)	0.0	0.0	(27.6)	0.0	(27.6)	(27.3)
2	Structures and improvements	(2.9)	(0.6)	0.2	0.8	(2.5)	0.1	(2.4)	(2.7)
3	Wells	(15.5)	(1.4)	0.9	0.0	(16.0)	0.0	(16.0)	(15.9)
4	Well equipment	(8.6)	(0.8)	0.4	0.0	(9.0)	0.0	(9.0)	(8.8)
5	Field Lines	(34.0)	(2.0)	0.1	0.0	(35.9)	0.0	(35.9)	(34.9)
6	Compressor equipment	(57.7)	(5.3)	0.5	1.6	(60.8)	0.3	(60.5)	(59.2)
7	Measuring and regulating equipment	(8.3)	(0.3)	0.0	0.0	(8.6)	0.0	(8.6)	(8.4)
8	Sub-Total	(154.0)	(10.9)	2.2	2.4	(160.3)	0.3	(160.0)	(157.2)
	Union Rate Zones Local Storage Plant								
9	Structures and improvements	(2.7)	(0.2)	0.0	0.0	(2.9)	0.0	(2.9)	(2.8)
10	Gas holders - storage	(3.9)	(0.1)	0.0	0.0	(4.1)	0.0	(4.1)	(4.0)
11	Gas holders - equipment	(11.0)	(0.7)	0.0	0.0	(11.7)	0.0	(11.7)	(11.4)
12	Regulatory Overheads	(0.6)	(0.1)	0.0	0.0	(0.7)	0.0	(0.7)	(0.6)
13	Sub-Total	(18.2)	(1.1)	0.0	0.0	(19.3)	0.0	(19.3)	(18.7)
	Union Rate Zones Underground Storage Plant								
14	Land rights	(18.8)	(0.7)	0.0	0.0	(19.5)	0.0	(19.5)	(19.1)
15	Structures and improvements	(43.9)	(1.8)	0.7	0.0	(45.0)	0.0	(45.0)	(44.6)
16	Wells	(34.2)	(1.2)	0.0	0.0	(35.4)	0.0	(35.4)	(34.8)
17	Field Lines	(29.6)	(1.3)	0.5	0.0	(30.4)	0.0	(30.4)	(30.1)
18	Compressor equipment	(168.2)	(12.7)	7.3	0.0	(173.5)	0.0	(173.5)	(172.8)
19	Measuring & regulating equipment	(43.0)	(2.0)	1.1	0.0	(43.9)	0.0	(43.9)	(43.7)
20	Regulatory Overheads	(4.1)	(0.6)	0.0	0.0	(4.7)	0.0	(4.7)	(4.4)
21	Sub-Total	(341.7)	(20.3)	9.6	0.0	(352.4)	0.0	(352.4)	(349.6)
22	EGI Total	(513.9)	(32.3)	11.8	2.4	(532.0)	0.3	(531.7)	(525.6)

Utility General Plant - EGI - Continuity of Accumulated Depreciation Year End Balances and Average of Monthly Averages
2022 Estimate

Line No.	Particulars ($ millions)	Dec. 2021 Opening Balance	Additions	Retirements	Costs Net of Proceeds	Dec. 2022 Closing Balance	Regulatory Adjustment	Dec. 2022 Utility Balance	Average of Monthly Averages
		(a)	(b)	(c)	(d)	(e) = (a+b+c+d)	(f)	(g) = (e+f)	(h)
	EGD Rate Zone General Plant								
1	Investment in leased assets	0.0	(1.2)	0.0	0.0	(1.2)	0.0	(1.2)	(0.6)
2	Lease improvements	(0.1)	0.0	0.0	0.0	(0.1)	0.2	0.1	0.1
3	Office furniture and equipment	(14.8)	(2.3)	0.4	0.0	(16.7)	0.0	(16.7)	(15.8)
4	Transportation equipment	(37.2)	(7.3)	2.6	0.0	(41.8)	0.1	(41.8)	(39.7)
5	NGV conversion kits	0.2	(0.3)	0.1	0.0	(0.0)	0.0	(0.0)	0.1
6	Heavy work equipment	(6.8)	(0.9)	0.5	0.0	(7.2)	0.0	(7.2)	(7.0)
7	Tools and work equipment	(24.7)	(2.6)	0.4	0.0	(26.9)	0.0	(26.9)	(25.8)
8	Rental equipment	(1.1)	(0.0)	0.0	0.0	(1.1)	0.0	(1.1)	(1.1)
9	NGV rental compressors	(2.5)	(0.7)	0.4	0.0	(2.7)	0.0	(2.7)	(2.6)
10	NGV cylinders	(0.5)	(0.0)	0.0	0.0	(0.6)	0.0	(0.6)	(0.5)
11	Communication structures & equip.	0.1	(0.2)	0.2	0.0	0.2	0.0	0.2	0.1
12	Computer equipment	(27.0)	(2.9)	3.7	0.0	(26.1)	0.0	(26.1)	(27.1)
13	Software Aquired/Developed	(218.4)	(59.7)	14.1	0.0	(264.0)	0.0	(264.0)	(247.3)
14	CIS	(21.8)	13.6	0.0	0.0	(8.2)	0.0	(8.2)	(8.8)
15	WAMS	(47.6)	(9.2)	0.0	0.0	(56.8)	0.0	(56.8)	(52.2)
16	Sub-Total	(402.1)	(73.6)	22.5	0.0	(453.3)	0.3	(453.0)	(428.2)
	Union Rate Zones General Plant								
17	Structures & improvements	(17.3)	(1.7)	0.4	0.0	(18.7)	0.0	(18.7)	(18.1)
18	Office furniture and equipment	(6.2)	(0.6)	0.2	0.0	(6.6)	0.0	(6.6)	(6.4)
19	Office equipment - computers	(47.1)	(21.4)	11.3	0.0	(57.2)	0.0	(57.2)	(55.1)
20	Transportation equipment	(52.8)	(8.9)	3.9	(4.0)	(61.8)	0.0	(61.8)	(57.2)
21	Heavy work equipment	(6.2)	(1.5)	0.4	0.0	(7.2)	0.0	(7.2)	(6.8)
22	Tools and work equipment	(17.2)	(2.4)	1.3	0.0	(18.4)	0.0	(18.4)	(18.1)
23	NGV fuel equipment	(1.6)	(0.2)	0.0	0.0	(1.7)	0.0	(1.7)	(1.7)
24	Communication equipment	(5.2)	(0.6)	0.2	0.0	(5.6)	0.0	(5.6)	(5.4)
25	Regulatory Overheads	(27.5)	(7.4)	0.0	0.0	(34.9)	0.0	(34.9)	(31.1)
26	Sub-Total	(181.0)	(44.7)	17.6	(4.0)	(212.1)	0.0	(212.1)	(199.9)
27	EGI Total	(583.1)	(118.4)	40.1	(4.0)	(665.4)	0.3	(665.1)	(628.2)

Utility Other Plant - EGI - Continuity of Accumulated Depreciation Year End Balances and Average of Monthly Averages
2022 Estimate

Line No.	Particulars ($ millions)	Dec. 2021 Opening Balance (a)	Additions (b)	Retirements (c)	Costs Net of Proceeds (d)	Dec. 2022 Closing Balance (e) = (a+b+c+d)	Regulatory Adjustment (f)	Dec. 2022 Utility Balance (g) = (e+f)	Average of Monthly Averages (h)
	EGD Rate Zone Plant held for future use								
1	Inactive services	(1.4)	(0.0)	0.0	0.0	(1.5)	0.0	(1.5)	(1.5)
	Union Rate Zones Intangible Plant								
2	Franchises and consents	(1.0)	(0.0)	0.0	0.0	(1.0)	0.0	(1.0)	(1.0)
3	Other intangible plant	(0.5)	(0.0)	0.0	0.0	(0.5)	0.0	(0.5)	(0.5)
4	Sub-Total	(1.5)	(0.0)	0.0	0.0	(1.5)	0.0	(1.5)	(1.5)
5	EGI Total	(2.9)	(0.0)	0.0	0.0	(2.9)	0.0	(2.9)	(2.9)

Utility Gross Distribution Plant - EGI - Year End Balances and Average of Monthly Averages
2023 Bridge Year

Line No.	Particulars ($ millions)	Dec. 2022 Opening Balance	Additions	Retirements	Dec. 2023 Closing Balance	Regulatory Adjustment	Dec. 2023 Utility Balance	Average of Monthly Averages	
		(a)	(b)	(c)	(d) = (a + b + c)	(e)	(f) = (d + e)	(g)	
	EGD Rate Zone Distribution Plant								
1	Renewable Natural Gas	12.1	11.1	0.0	23.2	0.0	23.2	15.8	
2	Land	92.7	0.2	(0.6)	92.3	0.0	92.3	92.6	
3	Offers to purchase	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
4	Land rights intangibles	64.3	1.3	0.0	65.6	0.0	65.6	64.7	
5	Structures and improvements	235.8	21.1	(5.8)	251.1	(0.3)	250.8	240.2	
6	Services, house reg & meter install.	3,641.9	184.6	(9.3)	3,817.2	0.0	3,817.2	3,700.4	
7	Mains	5,253.4	263.4	(29.7)	5,487.1	(2.2)	5,484.9	5,329.2	
8	NGV station compressors	5.2	0.9	0.0	6.2	0.0	6.2	5.6	
9	Measuring and regulating equip.	714.4	87.3	(4.4)	797.4	(0.5)	796.8	741.6	
10	Meters	548.6	47.8	(24.7)	571.6	0.0	571.6	556.3	
11	Sub-total	10,568.4	617.7	(74.4)	11,111.7	(3.1)	11,108.7	10,746.3	
	Union Rate Zones Distribution Plant - Southern Operations								
12	Land	18.2	1.4	0.0	19.6	0.0	19.6	18.6	
13	Land rights	9.2	0.6	0.0	9.8	0.0	9.8	9.4	
14	Structures and improvements	155.3	3.4	0.0	158.7	0.0	158.7	156.2	
15	Services - metallic	133.1	3.5	0.0	136.6	0.0	136.6	134.0	
16	Services - plastic	1,030.4	37.1	(1.4)	1,066.1	0.0	1,066.1	1,040.1	/u
17	Regulators	111.9	12.0	(1.9)	121.9	0.0	121.9	114.6	
18	House regulators & meter installations	91.0	6.3	(0.0)	97.2	0.0	97.2	92.7	
19	Mains - metallic	728.7	43.2	(0.7)	771.2	0.0	771.2	740.3	
20	Mains - plastic	791.8	46.2	(0.5)	837.5	0.0	837.5	804.2	/u
21	Measuring & regulating equipment	77.7	9.5	(0.1)	87.2	0.0	87.2	80.3	
22	Meters	422.0	30.8	(5.6)	447.2	0.0	447.2	428.8	/u
23	Regulatory Overheads	394.9	49.5	0.0	444.3	0.0	444.3	408.3	
24	Sub-total	3,964.2	243.5	(10.3)	4,197.4	0.0	4,197.4	4,027.4	/u

Utility Gross Distribution Plant - EGI - Year End Balances and Average of Monthly Averages (Continued)
2023 Bridge Year

Line No.	Particulars ($ millions)	Dec. 2022 Opening Balance	Additions	Retirements	Dec. 2023 Closing Balance	Regulatory Adjustment	Dec. 2023 Utility Balance	Average of Monthly Averages	
		(a)	(b)	(c)	(d) = (a + b + c)	(e)	(f) = (d + e)	(g)	
25	Land	5.7	0.4	0.0	6.2	0.0	6.2	5.9	
26	Land rights	11.1	0.7	0.0	11.8	0.0	11.8	11.3	
27	Structures and improvements	76.3	1.7	0.0	78.0	0.0	78.0	76.8	
28	Services - metallic	113.5	2.8	0.0	116.3	0.0	116.3	114.3	
29	Services - plastic	522.1	18.6	(0.7)	540.0	0.0	540.0	527.0	/u
30	Regulators	40.2	4.3	(0.7)	43.8	0.0	43.8	41.2	
31	House regulators & meter installations	44.0	2.9	(0.0)	46.8	0.0	46.8	44.7	
32	Mains - metallic	762.2	46.9	(0.7)	808.3	0.0	808.3	774.7	
33	Mains - plastic	260.8	14.8	(0.2)	275.4	0.0	275.4	264.8	/u
34	Measuring & regulating equipment	166.0	19.2	(0.1)	185.0	0.0	185.0	171.1	
35	Meters	110.1	8.0	(1.5)	116.7	0.0	116.7	111.9	/u
36	Regulatory Overheads	228.3	28.6	0.0	256.9	0.0	256.9	236.1	
37	Sub-total	2,340.4	149.0	(4.0)	2,485.4	0.0	2,485.4	2,379.7	/u
38	EGI Total	16,873.0	1,010.2	(88.7)	17,794.4	(3.1)	17,791.4	17,153.5	/u

Utility Transmission Plant - EGI - Year End Balances and Average of Monthly Averages
2023 Bridge Year

Line No.	Particulars ($ millions)	Dec. 2022 Opening Balance	Additions	Retirements	Dec. 2023 Closing Balance	Regulatory Adjustment	Dec. 2023 Utility Balance	Average of Monthly Averages
		(a)	(b)	(c)	(d) = (a + b + c)	(e)	(f) = (d + e)	(g)
	Union Rate Zones Transmission Plant							
1	Land	85.1	2.9	(1.2)	86.8	0.0	86.8	85.6
2	Land rights	68.5	2.6	0.0	71.1	0.0	71.1	69.2
3	Structures & improvements	167.8	0.3	(0.0)	168.0	0.0	168.0	167.8
4	Mains	2,061.5	166.7	(2.0)	2,226.2	0.0	2,226.2	2,106.1
5	Compressor equipment	950.7	3.1	0.0	953.8	0.0	953.8	951.5
6	Measuring & regulating equipment	418.9	43.5	(0.0)	462.3	0.0	462.3	430.7
7	Line Pack Gas	7.5	0.0	0.0	7.5	0.0	7.5	7.5
8	Regulatory Overheads	274.1	53.9	0.0	328.0	0.0	328.0	288.7
9	Total	4,034.0	272.9	(3.2)	4,303.7	0.0	4,303.7	4,107.2

Utility Storage Plant - EGI - Year End Balances and Average of Monthly Averages
2023 Bridge Year

Line No.	Particulars ($ millions)	Dec. 2022 Opening Balance	Additions	Retirements	Dec. 2023 Closing Balance	Regulatory Adjustment	Dec. 2023 Utility Balance	Average of Monthly Averages
		(a)	(b)	(c)	(d) = (a + b + c)	(e)	(f) = (d + e)	(g)
	EGD Rate Zone Underground Storage Plant							
1	Land and gas storage rights	49.5	0.0	0.0	49.5	(1.0)	48.4	48.4
2	Structures and improvements	32.3	0.0	(0.1)	32.3	(0.1)	32.2	32.2
3	Wells	98.5	4.5	(0.8)	102.2	0.0	102.2	99.7
4	Well equipment	15.5	0.9	(0.3)	16.0	0.0	16.0	15.7
5	Field Lines	140.5	3.4	0.0	143.9	0.0	143.9	141.6
6	Compressor equipment	211.4	15.8	(0.3)	226.9	(0.5)	226.4	216.1
7	Measuring and regulating equipment	11.2	0.0	0.0	11.2	0.0	11.2	11.2
8	Base pressure gas	32.4	0.0	0.0	32.4	0.0	32.4	32.4
9	Sub-Total	591.2	24.7	(1.6)	614.3	(1.5)	612.8	597.4
	Union Rate Zones Local Storage Plant							
10	Land	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	Structures and improvements	6.2	0.6	0.0	6.8	0.0	6.8	6.4
12	Gas holders - storage	5.9	0.1	0.0	5.9	0.0	5.9	5.9
13	Gas holders - equipment	20.2	0.0	0.0	20.2	0.0	20.2	20.2
14	Regulatory Overheads	4.3	3.0	0.0	7.4	0.0	7.4	5.1
15	Sub-Total	36.7	3.7	0.0	40.4	0.0	40.4	37.7
	Union Rate Zones Underground Storage Plant							
16	Land	9.6	1.9	0.0	11.5	0.0	11.5	10.2
17	Land rights	33.7	0.0	0.0	33.7	0.0	33.7	33.7
18	Structures and improvements	72.7	5.8	(0.2)	78.3	0.0	78.3	74.3
19	Wells	51.5	20.3	(0.0)	71.8	0.0	71.8	57.0
20	Field Lines	52.1	22.9	0.0	75.0	0.0	75.0	58.3
21	Compressor equipment	471.4	3.5	(0.7)	474.3	0.0	474.3	472.2
22	Measuring and regulating equipment	72.3	16.1	(0.9)	87.5	0.0	87.5	76.4

Utility Storage Plant - EGI - Year End Balances and Average of Monthly Averages (Continued)
2023 Bridge Year

Line No.	Particulars ($ millions)	Dec. 2022 Opening Balance	Additions	Retirements	Dec. 2023 Closing Balance	Regulatory Adjustment	Dec. 2023 Utility Balance	Average of Monthly Averages
		(a)	(b)	(c)	(d) = (a + b + c)	(e)	(f) = (d + e)	(g)
23	Base pressure gas	37.3	0.0	(0.1)	37.1	0.0	37.1	37.2
24	Regulatory Overheads	23.6	3.4	0.0	26.9	0.0	26.9	24.5
25	Sub-Total	824.3	73.8	(2.0)	896.2	0.0	896.2	843.8
26	EGI Total	1,452.2	102.2	(3.5)	1,550.8	(1.5)	1,549.3	1,478.9

Utility General Plant - EGI - Year End Balances and Average of Monthly Averages
2023 Bridge Year

Line No.	Particulars ($ millions)	Dec. 2022 Opening Balance	Additions	Retirements	Dec. 2023 Closing Balance	Regulatory Adjustment	Dec. 2023 Utility Balance	Average of Monthly Averages	
		(a)	(b)	(c)	(d) = (a + b + c)	(e)	(f) = (d + e)	(g)	
	EGD Rate Zone General Plant								
1	Investment in leased assets	26.3	7.6	0.0	33.9	0.0	33.9	28.8	
2	Lease improvements	0.1	0.0	0.0	0.1	(0.2)	(0.1)	(0.1)	
3	Office furniture and equipment	21.2	7.2	(0.0)	28.4	0.0	28.4	23.6	
4	Transportation equipment	72.8	6.1	(1.5)	77.4	(0.1)	77.3	74.2	/u
5	NGV conversion kits	3.0	0.2	0.0	3.2	0.0	3.2	3.1	/u
6	Heavy work equipment	27.0	2.0	(0.2)	28.8	0.0	28.8	27.6	
7	Tools and work equipment	68.4	4.6	(0.0)	72.9	0.0	72.9	69.9	
8	Rental equipment	1.8	(0.0)	0.0	1.8	0.0	1.8	1.8	
9	NGV rental compressors	7.5	(0.0)	0.0	7.5	0.0	7.5	7.5	
10	NGV cylinders	0.6	0.0	0.0	0.6	0.0	0.6	0.6	
11	Communication structures & equip.	1.6	0.1	(0.8)	1.0	0.0	1.0	1.4	
12	Computer equipment	29.9	11.4	(3.7)	37.6	0.0	37.6	32.4	
13	Software Aquired/Developed	278.1	48.4	(17.7)	308.9	0.0	308.9	288.2	
14	CIS	12.2	0.0	0.0	12.2	0.0	12.2	12.2	
15	WAMS	92.0	0.0	0.0	92.0	0.0	92.0	92.0	
16	Sub-Total	642.6	87.6	(23.8)	706.4	(0.3)	706.1	663.3	
	Union Rate Zones General Plant								
17	Land	0.5	0.0	0.0	0.5	0.0	0.5	0.5	
18	Structures & improvements	100.4	13.3	(0.1)	113.6	0.0	113.6	104.0	
19	Office furniture and equipment	9.5	0.3	(0.3)	9.5	0.0	9.5	9.5	
20	Office equipment - computers	127.6	7.4	(23.0)	112.0	0.0	112.0	123.3	
21	Transportation equipment	69.6	7.3	(5.4)	71.6	0.0	71.6	70.1	
22	Heavy work equipment	21.5	1.6	(0.8)	22.4	0.0	22.4	21.8	
23	Tools and work equipment	38.1	2.3	(2.0)	38.3	0.0	38.3	38.1	

Utility General Plant - EGI - Year End Balances and Average of Monthly Averages (Continued)
2023 Bridge Year

Line No.	Particulars ($ millions)	Dec. 2022 Opening Balance	Additions	Retirements	Dec. 2023 Closing Balance	Regulatory Adjustment	Dec. 2023 Utility Balance	Average of Monthly Averages
		(a)	(b)	(c)	(d) = (a + b + c)	(e)	(f) = (d + e)	(g)
24	NGV fuel equipment	5.2	0.4	0.0	5.6	0.0	5.6	5.3
25	Communication equipment	9.8	0.2	(1.6)	8.3	0.0	8.3	9.4
26	Regulatory Overheads	83.1	16.1	(3.3)	95.9	0.0	95.9	86.5
27	Sub-Total	465.3	48.8	(36.5)	477.6	0.0	477.6	468.6
28	EGI Total	1,107.9	136.4	(60.3)	1,184.0	(0.3)	1,183.7	1,131.9

Utility Other Plant -EGI - Year End Balances and Average of Monthly Averages
2023 Bridge Year

Line No.	Particulars ($ millions)	Dec. 2022 Opening Balance	Additions	Retirements	Dec. 2023 Closing Balance	Regulatory Adjustment	Dec. 2023 Utility Balance	Average of Monthly Averages
		(a)	(b)	(c)	(d) = (a + b + c)	(e)	(f) = (d + e)	(g)
	EGD Rate Zone Plant held for future use							
1	Inactive services	1.7	0.0	0.0	1.7	0.0	1.7	1.7
	Union Rate Zones Intangible Plant							
2	Franchises and consents	1.2	0.0	0.0	1.2	0.0	1.2	1.2
3	Other intangible plant	0.5	0.0	0.0	0.5	0.0	0.5	0.5
4	Sub-Total	1.7	0.0	0.0	1.7	0.0	1.7	1.7
5	EGI Total	3.3	0.0	0.0	3.3	0.0	3.3	3.3

Utility Distribution Plant - EGI - Continuity of Accumulated Depreciation Year End Balances and Average of Monthly Averages
2023 Bridge Year

Line No.	Particulars ($ millions)	Dec. 2022 Opening Balance (a)	Additions (b)	Retirements (c)	Costs Net of Proceeds (d)	Dec. 2023 Closing Balance (e) = (a + b + c + d)	Regulatory Adjustment (f)	Dec. 2023 Utility Balance (g) = (e + f)	Average of Monthly Averages (h)	
	EGD Rate Zone Distribution Plant									
1	Renewable Natural Gas	(0.3)	(0.7)	0.0	0.0	(1.0)	0.0	(1.0)	(0.6)	
2	Land rights intangibles	(7.3)	(0.8)	0.0	0.0	(8.0)	0.0	(8.0)	(7.6)	
3	Structures and improvements	(52.8)	(19.2)	5.8	2.4	(63.9)	0.3	(63.6)	(59.4)	
4	Services, house reg & meter install.	(1,186.9)	(84.2)	9.3	24.4	(1,237.4)	0.0	(1,237.4)	(1,217.4)	
5	Mains	(1,559.3)	(118.2)	29.7	13.2	(1,634.6)	2.2	(1,632.4)	(1,601.5)	/u
6	NGV station compressors	(3.8)	(0.3)	0.0	0.0	(4.2)	0.0	(4.2)	(4.0)	
7	Measuring and regulating equip.	(269.8)	(15.3)	4.4	1.0	(279.6)	0.5	(279.1)	(274.9)	
8	Meters	(358.3)	(51.4)	24.7	0.0	(384.9)	0.0	(384.9)	(375.6)	
9	Sub-total	(3,438.5)	(290.1)	73.9	41.0	(3,613.7)	3.1	(3,610.6)	(3,541.0)	/u
	Union Rate Zones Distribution Plant - Southern Operations									
10	Land rights	(2.6)	(0.2)	0.0	0.0	(2.7)	0.0	(2.7)	(2.7)	
11	Structures and improvements	(50.1)	(3.5)	0.0	0.0	(53.7)	0.0	(53.7)	(51.9)	
12	Services - metallic	(104.8)	(3.8)	0.0	3.5	(105.1)	0.0	(105.1)	(105.8)	
13	Services - plastic	(461.1)	(26.3)	1.4	4.7	(481.2)	0.0	(481.2)	(472.5)	/u
14	Regulators	(44.2)	(5.7)	1.9	0.0	(48.0)	0.0	(48.0)	(46.5)	
15	House regulators & meter installations	(33.7)	(2.6)	0.0	0.0	(36.2)	0.0	(36.2)	(34.9)	
16	Mains - metallic	(389.2)	(20.1)	0.7	2.8	(405.8)	0.0	(405.8)	(398.2)	
17	Mains - plastic	(317.6)	(18.7)	0.5	0.5	(335.3)	0.0	(335.3)	(326.6)	/u
18	Measuring & regulating equipment	(25.6)	(2.7)	0.1	0.2	(28.1)	0.0	(28.1)	(26.9)	
19	Meters	(126.7)	(16.8)	5.6	(0.2)	(138.0)	0.0	(138.0)	(133.5)	/u
20	Regulatory Overheads	(58.8)	(4.9)	0.0	0.0	(63.7)	0.0	(63.7)	(61.2)	
21	Sub-Total	(1,614.4)	(105.4)	10.3	11.5	(1,697.9)	0.0	(1,697.9)	(1,660.7)	/u
	Union Rate Zones Distribution Plant - Northern & Eastern Operations									
22	Land rights intangibles	(4.7)	(0.2)	0.0	0.0	(4.9)	0.0	(4.9)	(4.8)	
23	Structures and improvements	(29.8)	(1.9)	0.0	0.0	(31.7)	0.0	(31.7)	(30.7)	
24	Services - metallic	(79.7)	(3.7)	0.0	2.6	(80.8)	0.0	(80.8)	(80.8)	
25	Services - plastic	(239.0)	(13.8)	0.7	2.4	(249.7)	0.0	(249.7)	(245.0)	/u
26	Regulators	(16.7)	(2.1)	0.7	0.0	(18.1)	0.0	(18.1)	(17.5)	
27	House regulators & meter installations	(18.5)	(1.3)	0.0	0.0	(19.8)	0.0	(19.8)	(19.1)	
28	Mains - metallic	(385.5)	(24.3)	0.7	2.8	(406.2)	0.0	(406.2)	(396.6)	

Utility Distribution Plant - EGI - Continuity of Accumulated Depreciation Year End Balances and Average of Monthly Averages (Continued)
2023 Bridge Year

Line No.	Particulars ($ millions)	Dec. 2022 Opening Balance	Additions	Retirements	Costs Net of Proceeds	Dec. 2023 Closing Balance	Regulatory Adjustment	Dec. 2023 Utility Balance	Average of Monthly Averages	
		(a)	(b)	(c)	(d)	(e) = (a + b + c + d)	(f)	(g) = (e + f)	(h)	
29	Mains - plastic	(125.3)	(6.4)	0.2	0.2	(131.3)	0.0	(131.3)	(128.4)	/u
30	Measuring & regulating equipment	(87.6)	(6.7)	0.1	0.5	(93.6)	0.0	(93.6)	(90.7)	
31	Meters	(30.9)	(4.5)	1.5	(0.0)	(33.9)	0.0	(33.9)	(32.7)	/u
32	Regulatory Overheads	(41.6)	(13.6)	0.0	0.0	(55.2)	0.0	(55.2)	(48.3)	
33	Sub-Total	(1,059.3)	(78.5)	4.0	8.6	(1,125.2)	0.0	(1,125.2)	(1,094.7)	/u
34	EGI Total	(6,112.1)	(473.9)	88.1	61.1	(6,436.8)	3.1	(6,433.7)	(6,296.5)	/u

Utility Transmission Plant - EGI - Continuity of Accumulated Depreciation Year End Balances and Average of Monthly Averages
2023 Bridge Year

Line No.	Particulars ($ millions)	Dec. 2022 Opening Balance	Additions	Retirements	Costs Net of Proceeds	Dec. 2023 Closing Balance	Regulatory Adjustment	Dec. 2023 Utility Balance	Average of Monthly Averages
		(a)	(b)	(c)	(d)	(e) = (a + b + c + d)	(f)	(g) = (e + f)	(h)
	Union Rate Zones Transmission Plant								
1	Land rights	(20.5)	(1.2)	0.0	0.0	(21.7)	0.0	(21.7)	(21.1)
2	Structures & improvements	(49.6)	(3.4)	0.0	0.0	(53.0)	0.0	(53.0)	(51.3)
3	Mains	(733.9)	(41.8)	2.0	0.2	(773.5)	0.0	(773.5)	(753.9)
4	Compressor equipment	(354.1)	(30.7)	0.0	0.0	(384.8)	0.0	(384.8)	(369.5)
5	Measuring & regulating equipment	(125.9)	(11.2)	0.0	0.0	(137.1)	0.0	(137.1)	(131.5)
6	Regulatory Overheads	(34.1)	(7.3)	0.0	0.0	(41.3)	0.0	(41.3)	(37.6)
8	Total	(1,318.0)	(95.7)	2.0	0.3	(1,411.4)	0.0	(1,411.4)	(1,364.9)

Utility Storage Plant - EGI - Continuity of Accumulated Depreciation Year End Balances and Average of Monthly Averages
2023 Bridge Year

Line No.	Particulars ($ millions)	Dec. 2022 Opening Balance	Additions	Retirements	Costs Net of Proceeds	Dec. 2023 Closing Balance	Regulatory Adjustment	Dec. 2023 Utility Balance	Average of Monthly Averages
		(a)	(b)	(c)	(d)	(e) = (a + b + c + d)	(f)	(g) = (e + f)	(h)
	EGD Rate Zone Underground Storage Plant								
1	Land and gas storage rights	(27.6)	(0.5)	0.0	0.0	(28.1)	0.0	(28.1)	(27.8)
2	Structures and improvements	(2.5)	(0.6)	0.1	0.7	(2.3)	0.1	(2.2)	(2.4)
3	Wells	(16.0)	(1.5)	0.8	0.0	(16.7)	0.0	(16.7)	(16.5)
4	Well equipment	(9.0)	(0.9)	0.3	0.0	(9.5)	0.0	(9.5)	(9.3)
5	Field Lines	(35.9)	(2.1)	0.0	0.0	(38.0)	0.0	(38.0)	(36.9)
6	Compressor equipment	(60.8)	(5.6)	0.3	1.5	(64.7)	0.3	(64.4)	(62.7)
7	Measuring and regulating equipment	(8.6)	(0.3)	0.0	0.0	(8.9)	0.0	(8.9)	(8.7)
8	Sub-Total	(160.3)	(11.6)	1.6	2.2	(168.1)	0.4	(167.8)	(164.5)
	Union Rate Zones Local Storage Plant								
9	Structures and improvements	(2.9)	(0.2)	0.0	0.1	(3.0)	0.0	(3.0)	(2.9)
10	Gas holders - storage	(4.1)	(0.1)	0.0	0.0	(4.2)	0.0	(4.2)	(4.1)
11	Gas holders - equipment	(11.7)	(0.7)	0.0	0.0	(12.4)	0.0	(12.4)	(12.1)
12	Regulatory Overheads	(0.7)	(0.2)	0.0	0.0	(0.8)	0.0	(0.8)	(0.7)
13	Sub-Total	(19.3)	(1.2)	0.0	0.1	(20.4)	0.0	(20.4)	(19.9)
	Union Rate Zones Underground Storage Plant								
14	Land rights	(19.5)	(0.7)	0.0	0.0	(20.2)	0.0	(20.2)	(19.8)
15	Structures and improvements	(45.0)	(1.9)	0.2	0.0	(46.6)	0.0	(46.6)	(45.8)
16	Wells	(35.4)	(1.4)	0.0	0.0	(36.8)	0.0	(36.8)	(36.1)
17	Field Lines	(30.4)	(1.5)	0.0	0.0	(31.9)	0.0	(31.9)	(31.1)
18	Compressor equipment	(173.5)	(12.7)	0.7	0.0	(185.5)	0.0	(185.5)	(179.7)
19	Measuring & regulating equipment	(43.9)	(2.4)	0.9	0.1	(45.3)	0.0	(45.3)	(44.8)
20	Regulatory Overheads	(4.7)	(0.7)	0.0	0.0	(5.4)	0.0	(5.4)	(5.1)
21	Sub-Total	(352.4)	(21.2)	1.9	0.1	(371.7)	0.0	(371.7)	(362.4)
22	EGI Total	(532.0)	(34.0)	3.4	2.3	(560.3)	0.4	(559.9)	(546.7)

Utility General Plant - EGI - Continuity of Accumulated Depreciation Year End Balances and Average of Monthly Averages
2023 Bridge Year

Line No.	Particulars ($ millions)	Dec. 2022 Opening Balance (a)	Additions (b)	Retirements (c)	Costs Net of Proceeds (d)	Dec. 2023 Closing Balance (e) = (a + b + c + d)	Regulatory Adjustment (f)	Dec. 2023 Utility Balance (g) = (e + f)	Average of Monthly Averages (h)
	EGD Rate Zone General Plant								
1	Investment in leased assets	(1.2)	(1.8)	0.0	0.0	(3.1)	0.0	(3.1)	(2.1)
2	Lease improvements	(0.1)	0.0	0.0	0.0	(0.1)	0.2	0.1	0.1
3	Office furniture and equipment	(16.7)	(2.9)	0.0	0.0	(19.6)	0.0	(19.6)	(18.2)
4	Transportation equipment	(41.8)	(7.9)	1.5	0.0	(48.2)	0.1	(48.2)	(45.2)
5	NGV conversion kits	(0.0)	(0.3)	0.0	0.0	(0.3)	0.0	(0.3)	(0.1)
6	Heavy work equipment	(7.2)	(1.0)	0.2	0.0	(8.0)	0.0	(8.0)	(7.6)
7	Tools and work equipment	(26.9)	(2.9)	0.0	0.0	(29.8)	0.0	(29.8)	(28.3)
8	Rental equipment	(1.1)	(0.0)	0.0	0.0	(1.1)	0.0	(1.1)	(1.1)
9	NGV rental compressors	(2.7)	(0.6)	0.0	0.0	(3.3)	0.0	(3.3)	(3.0)
10	NGV cylinders	(0.6)	(0.0)	0.0	0.0	(0.6)	0.0	(0.6)	(0.6)
11	Communication structures & equip.	0.2	(0.1)	0.8	0.0	0.8	0.0	0.8	0.4
12	Computer equipment	(26.1)	(10.3)	3.7	0.0	(32.8)	0.0	(32.8)	(30.1)
13	Software Aquired/Developed	(264.0)	(42.1)	17.7	0.0	(288.4)	0.0	(288.4)	(280.0)
14	CIS	(8.2)	(1.2)	0.0	0.0	(9.4)	0.0	(9.4)	(8.8)
15	WAMS	(56.8)	(9.2)	0.0	0.0	(66.0)	0.0	(66.0)	(61.4)
16	Sub-Total	(453.3)	(80.4)	23.8	0.0	(509.9)	0.3	(509.6)	(486.2)
	Union Rate Zones General Plant								
17	Structures & improvements	(18.7)	(2.0)	0.1	0.0	(20.5)	0.0	(20.5)	(19.6)
18	Office furniture and equipment	(6.6)	(0.6)	0.3	0.0	(7.0)	0.0	(7.0)	(6.9)
19	Office equipment - computers	(57.2)	(16.7)	23.0	0.0	(50.9)	0.0	(50.9)	(62.4)
20	Transportation equipment	(61.8)	(9.3)	5.4	(2.3)	(68.0)	0.0	(68.0)	(65.6)
21	Heavy work equipment	(7.2)	(1.5)	0.8	0.0	(8.0)	0.0	(8.0)	(7.8)
22	Tools and work equipment	(18.4)	(2.5)	2.0	0.0	(18.9)	0.0	(18.9)	(19.1)
23	NGV fuel equipment	(1.7)	(0.2)	0.0	0.0	(2.0)	0.0	(2.0)	(1.9)
24	Communication equipment	(5.6)	(0.6)	1.6	0.0	(4.5)	0.0	(4.5)	(5.4)
25	Regulatory Overheads	(34.9)	(8.7)	3.3	0.0	(40.3)	0.0	(40.3)	(38.3)
26	Sub-Total	(212.1)	(42.2)	36.5	(2.3)	(220.1)	0.0	(220.1)	(226.8)
27	EGI Total	(665.4)	(122.6)	60.3	(2.3)	(730.0)	0.3	(729.7)	(713.1)

Utility Other Plant - EGI - Continuity of Accumulated Depreciation Year End Balances and Average of Monthly Averages
2023 Bridge Year

Line No.	Particulars ($ millions)	Dec. 2022 Opening Balance	Additions	Retirements	Costs Net of Proceeds	Dec. 2023 Closing Balance	Regulatory Adjustment	Dec. 2023 Utility Balance	Average of Monthly Averages
		(a)	(b)	(c)	(d)	(e) = (a + b + c + d)	(f)	(g) = (e + f)	(h)
	EGD Rate Zone Plant held for future use								
1	Inactive services	(1.5)	0.0	0.0	0.0	(1.5)	0.0	(1.5)	(1.5)
	Union Rate Zones Intangible Plant								
2	Franchises and consents	(1.0)	0.0	0.0	0.0	(1.0)	0.0	(1.0)	(1.0)
3	Other intangible plant	(0.5)	0.0	0.0	0.0	(0.5)	0.0	(0.5)	(0.5)
4	Sub-Total	(1.5)	0.0	0.0	0.0	(1.5)	0.0	(1.5)	(1.5)
5	EGI Total	(2.9)	0.0	0.0	0.0	(2.9)	0.0	(2.9)	(2.9)

Utility Gross Distribution Plant - EGI - Year End Balances and Average of Monthly Averages
2024 Test Year

Line No.	Particulars ($ millions)	Dec. 2023 Opening Balance	Transfers	Restated Opening Balance	Additions	Retirements	Dec. 2024 Closing Balance	Regulatory Adjustment	Dec. 2024 Utility Balance	Average of Monthly Averages	
		(a)	(b)	(c) = (a + b)	(d)	(e)	(f) = (c + d + e)	(g)	(h) = (f + g)	(i)	
1	Renewable Natural Gas	23.2	0.0	23.2	16.4	0.0	39.6	0.0	39.6	28.1	
2	Land	118.1	(0.1)	118.1	3.6	(5.0)	116.6	0.0	116.6	117.6	
3	Land rights	87.2	(19.9)	67.3	1.3	0.0	68.6	0.0	68.6	67.7	
4	Structures and improvements	487.8	(141.3)	346.6	82.9	(38.4)	391.1	(0.3)	390.7	362.1	
5	Services - metallic	4,070.1	(3,473.7)	596.3	30.8	(0.7)	626.4	0.0	626.4	605.8	/u
6	Services - plastic	1,606.1	3,287.6	4,893.7	294.4	(9.3)	5,178.8	0.0	5,178.8	4,984.3	/u
7	Regulators	165.8	329.6	495.3	39.1	(13.1)	521.3	0.0	521.3	502.8	
8	House regulators & meter installations	144.1	20.3	164.4	20.0	(0.1)	184.4	0.0	184.4	169.8	
9	Mains - metallic	7,066.6	(3,135.6)	3,931.0	176.4	(21.0)	4,086.5	(2.2)	4,084.3	3,974.6	
10	Mains - plastic	1,112.9	2,616.5	3,729.4	230.2	(10.9)	3,948.7	0.0	3,948.7	3,797.5	/u
11	Mans - envision	0.0	208.0	208.0	28.4	0.0	236.4	0.0	236.4	217.5	
12	NGV station compressors	6.2	5.8	12.0	0.9	0.0	12.9	0.0	12.9	12.3	
13	Measuring & regulating equipment	1,069.6	33.2	1,102.8	64.1	(4.6)	1,162.3	(0.5)	1,161.8	1,119.5	
14	Meters	1,135.5	0.0	1,135.5	89.8	(31.8)	1,193.5	0.0	1,193.5	1,152.7	/u
15	Regulatory Overheads	701.3	(701.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
16	Total	17,794.4	(970.8)	16,823.6	1,078.4	(134.8)	17,767.2	(3.1)	17,764.1	17,112.2	/u

Utility Transmission Plant - EGI - Year End Balances and Average of Monthly Averages
2024 Test Year

Line No	Particulars ($ millions)	Dec. 2023 Opening Balance	Transfers	Restated Opening Balance	Additions	Retirements	Dec. 2024 Closing Balance	Regulatory Adjustment	Dec. 2024 Utility Balance	Average of Monthly Averages
		(a)	(b)	(c) = (a + b)	(d)	(e)	(f) = (c + d + e)	(g)	(h) = (f + g)	(i)
1	Land	86.8	0.0	86.9	2.1	(1.2)	87.8	0.0	87.8	87.1
2	Land rights	71.1	19.9	91.0	1.6	0.0	92.6	0.0	92.6	91.4
3	Structures & improvements	168.0	13.6	181.7	0.7	(0.0)	182.3	0.0	182.3	181.9
4	Mains	2,226.2	834.9	3,061.0	137.1	(2.0)	3,196.1	0.0	3,196.1	3,097.7
5	Compressor equipment	953.8	77.2	1,031.0	1.6	0.0	1,032.6	0.0	1,032.6	1,031.4
6	Measuring & regulating equipment	462.3	41.3	503.6	45.6	(0.0)	549.2	0.0	549.2	515.9
7	Line Pack Gas	7.5	0.0	7.5	0.0	0.0	7.5	0.0	7.5	7.5
8	Regulatory Overheads	328.0	(328.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Total	4,303.7	658.9	4,962.6	188.7	(3.2)	5,148.1	0.0	5,148.1	5,012.9

Utility Storage Plant - EGI - Year End Balances and Average of Monthly Averages
2024 Test Year

Line No.	Particulars ($ millions)	Dec. 2023 Opening Balance	Transfers	Restated Opening Balance	Additions	Retirements	Dec. 2024 Closing Balance	Regulatory Adjustment	Dec. 2024 Utility Balance	Average of Monthly Averages
		(a)	(b)	(c) = (a + b)	(d)	(e)	(f) = (c + d + e)	(g)	(h) = (f + g)	(i)
	Underground Storage Plant									
1	Land	11.5	6.7	18.2	0.1	0.0	18.3	(1.0)	17.3	17.2
2	Land rights	83.2	(6.7)	76.5	0.0	0.0	76.5	0.0	76.5	76.5
3	Structures and improvements	110.6	2.8	113.4	5.2	(0.3)	118.2	(0.1)	118.2	114.6
4	Wells	174.0	2.5	176.5	35.6	(0.8)	211.3	0.0	211.3	187.1
5	Well equipment	16.0	0.0	16.0	2.9	(0.3)	18.6	0.0	18.6	16.9
6	Field Lines	218.9	22.8	241.7	34.6	0.0	276.3	0.0	276.3	252.1
7	Compressor equipment	701.1	16.7	717.8	17.0	(1.0)	733.8	(0.5)	733.3	722.6
8	Measuring and regulating equipment	98.7	3.6	102.3	14.2	(0.9)	115.5	0.0	115.5	105.9
9	Base pressure gas	69.5	0.0	69.5	0.0	(0.1)	69.4	0.0	69.4	69.5
10	Regulatory Overheads	26.9	(26.9)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	Sub-Total	1,510.5	21.5	1,531.9	109.5	(3.5)	1,637.9	(1.5)	1,636.4	1,562.4
	Local Storage Plant									
12	Land	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	Structures and improvements	6.8	1.5	8.3	0.3	0.0	8.7	0.0	8.7	8.4
14	Gas holders - storage	5.9	1.3	7.3	0.0	0.0	7.3	0.0	7.3	7.3
15	Gas holders - equipment	20.2	4.5	24.8	0.0	0.0	24.8	0.0	24.8	24.8
16	Regulatory Overheads	7.4	(7.4)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
17	Sub-Total	40.4	0.0	40.4	0.3	0.0	40.7	0.0	40.7	40.5
18	EGI Total	1,550.8	21.5	1,572.3	109.9	(3.5)	1,678.6	(1.5)	1,677.1	1,602.8

Utility General Plant - EGI - Year End Balances and Average of Monthly Averages
2024 Test Year

Line No.	Particulars ($ millions)	Dec. 2023 Opening Balance	Transfers	Restated Opening Balance	Additions	Retirements	Dec. 2024 Closing Balance	Regulatory Adjustment	Dec. 2024 Utility Balance	Average of Monthly Averages
		(a)	(b)	(c) = (a + b)	(d)	(e)	(f) = (c + d + e)	(g)	(h) = (f + g)	(i)
1	Investment in leased assets	33.9	0.0	33.9	7.6	0.0	41.5	0.0	41.5	37.1
2	Land	0.5	0.0	0.5	0.0	0.0	0.5	0.0	0.5	0.5
3	Structures and improvements	113.7	179.8	293.5	1.7	(0.1)	295.1	(0.2)	294.9	293.7
4	Office furniture and equipment	149.9	(113.5)	36.3	4.5	(1.2)	39.6	0.0	39.6	37.5
5	Transportation equipment	149.0	(1.9)	147.1	17.4	(6.8)	157.6	(0.1)	157.6	150.3
6	NGV conversion kits	3.2	0.5	3.7	0.2	0.0	3.9	0.0	3.9	3.7
7	Heavy work equipment	51.2	(0.7)	50.5	4.8	(1.0)	54.3	0.0	54.3	51.7
8	Tools and work equipment	111.2	(21.6)	89.7	8.8	(4.3)	94.1	0.0	94.1	91.1
9	NGV rental equipment	15.6	(6.7)	8.8	0.0	0.0	8.8	0.0	8.8	8.8
10	Communication structures & equip.	9.3	0.9	10.2	0.4	(1.6)	8.9	0.0	8.9	9.8
11	Computer equipment	37.6	2.3	39.9	24.2	(7.9)	56.3	0.0	56.3	45.2
12	Software Aquired/Developed	321.0	31.9	352.9	57.4	(61.6)	348.7	0.0	348.7	352.1
13	WAMS	92.0	(2.1)	89.9	0.0	0.0	89.9	0.0	89.9	89.9
14	Regulatory Overheads	95.9	(95.9)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	Total	1,184.0	(27.0)	1,157.0	127.0	(84.5)	1,199.4	(0.3)	1,199.2	1,171.5

Utility Other Plant -EGI - Year End Balances and Average of Monthly Averages
2024 Test Year

Line No.	Particulars ($ millions)	Dec. 2023 Opening Balance	Transfers	Restated Opening Balance	Additions	Retirements	Dec. 2024 Closing Balance	Regulatory Adjustment	Dec. 2024 Utility Balance	Average of Monthly Averages
		(a)	(b)	(c) = (a + b)	(d)	(e)	(f) = (c + d + e)	(g)	(h) = (f + g)	(i)
1	Inactive services	1.7	0.0	1.7	0.0	0.0	1.7	0.0	1.7	1.7
2	Franchises and consents	1.2	0.0	1.2	0.0	0.0	1.2	0.0	1.2	1.2
3	Other intangible plant	0.5	0.0	0.5	0.0	0.0	0.5	0.0	0.5	0.5
4	Total	3.3	0.0	3.3	0.0	0.0	3.3	0.0	3.3	3.3

Utility Distribution Plant - EGI - Continuity of Accumulated Depreciation Year End Balances and Average of Monthly Averages
2024 Test Year

Line No.	Particulars ($ millions)	Dec. 2023 Opening Balance	Transfers	Restated Opening Balance	Additions	Retirements	Costs Net of Proceeds	Dec. 2024 Closing Balance	Regulatory Adjustment	Dec. 2024 Utility Balance	Average of Monthly Averages	
		(a)	(b)	(c) = (a + b)	(d)	(e)	(f)	(g) = (c + d + e + f)	(h)	(i) = (g + h)	(j)	
1	Renewable Natural Gas	(1.0)	0.0	(1.0)	(1.2)	0.0	0.0	(2.2)	0.0	(2.2)	(1.5)	
2	Land rights	(15.6)	1.3	(14.3)	(1.2)	0.0	0.0	(15.5)	0.0	(15.5)	(14.9)	
3	Structures and improvements	(149.3)	46.2	(103.1)	(22.2)	38.4	0.0	(86.9)	0.3	(86.5)	(102.1)	
4	Services - metallic	(1,423.3)	1,132.1	(291.3)	(22.0)	0.7	5.1	(307.5)	0.0	(307.5)	(300.4)	/u
5	Services - plastic	(730.9)	(1,076.4)	(1,807.3)	(136.3)	9.3	29.0	(1,905.2)	0.0	(1,905.2)	(1,862.3)	/u
6	Regulators	(66.1)	23.3	(42.8)	(44.7)	13.1	2.5	(71.8)	0.0	(71.8)	(59.9)	
7	House regulators & meter installations	(56.0)	(3.4)	(59.5)	(5.7)	0.1	0.0	(65.1)	0.0	(65.1)	(62.3)	
8	Mains - metallic	(2,446.7)	905.3	(1,541.3)	(134.7)	21.0	12.4	(1,642.6)	2.2	(1,640.4)	(1,595.2)	
9	Mains - plastic	(466.6)	(706.2)	(1,172.8)	(103.5)	10.9	0.3	(1,265.1)	0.0	(1,265.1)	(1,220.4)	/u
10	Mans - envision	0.0	(62.8)	(62.8)	(12.6)	0.0	6.8	(68.6)	0.0	(68.6)	(66.7)	
11	NGV station compressors	(4.2)	(2.0)	(6.2)	(0.5)	0.0	0.0	(6.6)	0.0	(6.6)	(6.4)	
12	Measuring & regulating equipment	(401.3)	(5.8)	(407.2)	(32.4)	4.6	1.6	(433.3)	0.5	(432.8)	(420.7)	
13	Meters	(556.9)	0.0	(556.9)	(118.5)	31.8	(0.0)	(643.6)	0.0	(643.6)	(605.5)	/u
14	Regulatory Overheads	(118.9)	118.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
15	Total	(6,436.8)	370.5	(6,066.3)	(635.3)	129.8	57.7	(6,514.0)	3.1	(6,510.9)	(6,318.2)	/u

Utility Transmission Plant - EGI - Continuity of Accumulated Depreciation Year End Balances and Average of Monthly Averages
2024 Test Year

Line No.	Particulars ($ millions)	Dec. 2023 Opening Balance	Transfers	Restated Opening Balance	Additions	Retirements	Costs Net of Proceeds	Dec. 2024 Closing Balance	Regulatory Adjustment	Dec. 2024 Utility Balance	Average of Monthly Averages
		(a)	(b)	(c) = (a + b)	(d)	(e)	(f)	(g) = (c + d + e + f)	(h)	(i) = (g + h)	(j)
1	Land rights	(21.7)	(1.3)	(23.0)	(1.6)	0.0	0.0	(24.6)	0.0	(24.6)	(23.8)
2	Structures & improvements	(53.0)	(1.7)	(54.7)	(3.7)	0.0	0.0	(58.4)	0.0	(58.4)	(56.5)
3	Mains	(773.5)	(230.8)	(1,004.3)	(54.9)	2.0	0.1	(1,057.1)	0.0	(1,057.1)	(1,031.0)
4	Compressor equipment	(384.8)	(9.7)	(394.6)	(38.4)	0.0	0.0	(433.0)	0.0	(433.0)	(413.8)
5	Measuring & regulating equipment	(137.1)	(5.2)	(142.3)	(15.9)	0.0	0.0	(158.1)	0.0	(158.1)	(150.1)
6	Regulatory Overheads	(41.3)	41.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	Total	(1,411.4)	(207.4)	(1,618.9)	(114.4)	2.0	0.1	(1,731.1)	0.0	(1,731.1)	(1,675.2)

Utility Storage Plant - EGI - Continuity of Accumulated Depreciation Year End Balances and Average of Monthly Averages
2024 Test Year

Line No.	Particulars ($ millions)	Dec. 2023 Opening Balance	Transfers	Restated Opening Balance	Additions	Retirements	Costs Net of Proceeds	Dec. 2024 Closing Balance	Regulatory Adjustment	Dec. 2024 Utility Balance	Average of Monthly Averages
		(a)	(b)	(c) = (a + b)	(d)	(e)	(f)	(g) = (c + d + e + f)	(h)	(i) = (g + h)	(j)
	Underground Storage Plant										
1	Land rights	(48.2)	0.0	(48.2)	(1.1)	0.0	0.0	(49.4)	0.0	(49.4)	(48.8)
2	Structures and improvements	(48.9)	(0.6)	(49.5)	(4.5)	0.3	0.9	(52.8)	0.1	(52.7)	(51.2)
3	Wells	(53.6)	(0.5)	(54.1)	(7.3)	0.8	0.0	(60.5)	0.0	(60.5)	(57.3)
4	Well equipment	(9.5)	0.0	(9.5)	(0.2)	0.3	0.0	(9.4)	0.0	(9.4)	(9.5)
5	Field Lines	(69.9)	10.4	(59.5)	(6.4)	0.0	0.0	(65.9)	0.0	(65.9)	(62.7)
6	Compressor equipment	(250.1)	(3.4)	(253.5)	(20.9)	1.0	1.9	(271.5)	0.3	(271.1)	(262.7)
7	Measuring and regulating equipment	(54.2)	(0.7)	(54.9)	(2.8)	0.9	0.0	(56.7)	0.0	(56.7)	(56.0)
8	Regulatory Overheads	(5.4)	5.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Sub-Total	(539.9)	10.6	(529.2)	(43.2)	3.4	2.8	(566.2)	0.4	(565.8)	(548.3)
	Local Storage Plant										
10	Land	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	Structures and improvements	(3.0)	(0.2)	(3.1)	(0.1)	0.0	0.0	(3.2)	0.0	(3.2)	(3.2)
12	Gas holders - storage	(4.2)	(0.1)	(4.4)	(0.1)	0.0	0.0	(4.4)	0.0	(4.4)	(4.4)
13	Gas holders - equipment	(12.4)	(0.5)	(12.9)	(0.3)	0.0	0.0	(13.2)	0.0	(13.2)	(13.1)
14	Regulatory Overheads	(0.8)	0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	Sub-Total	(20.4)	0.0	(20.4)	(0.5)	0.0	0.0	(20.8)	0.0	(20.8)	(20.6)
16	Total	(560.3)	10.6	(549.7)	(43.7)	3.4	2.9	(587.0)	0.4	(586.7)	(568.9)

Utility General Plant - EGI - Continuity of Accumulated Depreciation Year End Balances and Average of Monthly Averages
2024 Test Year

Line No.	Particulars ($ millions)	Dec. 2023 Opening Balance	Transfers	Restated Opening Balance	Additions	Retirements	Costs Net of Proceeds	Dec. 2024 Closing Balance	Regulatory Adjustment	Dec. 2024 Utility Balance	Average of Monthly Averages
		(a)	(b)	(c) = (a + b)	(d)	(e)	(f)	(g) = (c + d + e + f)	(h)	(i) = (g + h)	(j)
1	Investment in leased assets	(3.1)	0.0	(3.1)	(1.5)	0.0	0.0	(4.6)	0.0	(4.6)	(3.8)
2	Structures & improvements	(20.6)	(53.2)	(73.9)	(17.2)	0.1	3.0	(87.9)	0.2	(87.7)	(81.2)
3	Office furniture and equipment	(77.5)	52.3	(25.2)	(1.5)	1.2	0.0	(25.5)	0.0	(25.5)	(25.6)
4	Transportation equipment	(116.2)	1.2	(115.0)	(7.0)	6.8	(0.9)	(116.2)	0.1	(116.1)	(116.8)
5	NGV conversion kits	(0.3)	(0.5)	(0.8)	(0.1)	0.0	0.0	(1.0)	0.0	(1.0)	(0.9)
6	Heavy work equipment	(16.0)	0.2	(15.8)	(4.3)	1.0	0.0	(19.1)	0.0	(19.1)	(17.6)
7	Tools and work equipment	(48.6)	20.6	(28.0)	(10.9)	4.3	0.0	(34.5)	0.0	(34.5)	(32.1)
8	NGV rental equipment	(7.0)	3.2	(3.8)	(0.4)	0.0	0.0	(4.2)	0.0	(4.2)	(4.0)
9	Communication structures & equip.	(3.7)	(0.9)	(4.7)	(2.6)	1.6	0.0	(5.6)	0.0	(5.6)	(5.5)
10	Computer equipment	(32.8)	8.3	(24.5)	(7.5)	7.9	0.0	(24.1)	0.0	(24.1)	(25.4)
11	Software Aquired/Developed	(297.9)	64.1	(233.7)	(36.4)	61.6	0.0	(208.6)	0.0	(208.6)	(231.4)
12	WAMS	(66.0)	1.5	(64.4)	(9.7)	0.0	0.0	(74.1)	0.0	(74.1)	(69.3)
13	Regulatory Overheads	(40.3)	40.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	Total	(730.0)	137.1	(592.9)	(99.1)	84.5	2.1	(605.4)	0.3	(605.1)	(613.6)

Utility Other Plant - EGI - Continuity of Accumulated Depreciation Year End Balances and Average of Monthly Averages
2024 Test Year

Line No.	Particulars ($ millions)	Dec. 2023 Opening Balance	Transfers	Restated Opening Balance	Additions	Retirements	Costs Net of Proceeds	Dec. 2024 Closing Balance	Regulatory Adjustment	Dec. 2024 Utility Balance	Average of Monthly Averages
		(a)	(b)	(c) = (a + b)	(d)	(e)	(f)	(g) = (c + d + e + f)	(h)	(i) = (g + h)	(j)
1	Inactive services	(1.5)	0.0	(1.5)	0.0	0.0	0.0	(1.5)	0.0	(1.5)	(1.5)
2	Franchises and consents	(1.0)	0.0	(1.0)	0.0	0.0	0.0	(1.0)	0.0	(1.0)	(1.0)
3	Other intangible plant	(0.5)	0.0	(0.5)	0.0	0.0	0.0	(0.5)	0.0	(0.5)	(0.5)
4	Total	(2.9)	0.0	(2.9)	0.0	0.0	0.0	(2.9)	0.0	(2.9)	(2.9)

ALLOWANCE FOR WORKING CAPITAL

JASON VINAGRE, MANAGER REGULATORY ACCOUNTING

1. The purpose of this evidence is to present the allowance for working capital component of utility rate base and to request approval of the 2024 Test Year allowance for working capital.

2. This evidence is organized as follows:
   1. 2024 Test Year Allowance for Working Capital
   2. Harmonization of Allowance for Working Capital Components
   3. Historical and Forecast Comparatives

3. The allowance for working capital represents the funds required to finance the day-to-day operations of Enbridge Gas and is a component of overall utility rate base. The utility rate base evidence and summaries are provided at Exhibit 2, Tab 1, Schedule 1. A summary of EGD and Union's allowance for working capital from 2013 OEB-approved to 2018 actual is provided at Attachment 1. The same attachment also sets out the Enbridge Gas allowance for working capital for 2019 to 2021 actuals, the 2022 Estimate, the 2023 Bridge Year, and the 2024 Test Year.

4. The 2024 Test Year working cash allowance calculation is provided at Attachment 2. The details of the 2024 Test Year working capital average of monthly averages calculation, along with monthly gas in storage volumes, are provided at Attachment 3. Determination of the 2024 Test Year working cash allowance is supported by the Enbridge Gas 2021 Lead-Lag Study (the Lead-Lag Study) provided at Exhibit 2, Tab 3, Schedule 2, Attachment 1.

1. 2024 Test Year Allowance for Working Capital

5. Table 1 sets out the average forecast balance of all allowance for working capital components for the 2024 Test Year. The calculation consists of a 2024 monthly forecast of materials and supplies, customer security deposits, Distributor Consolidated Billing (DCB) receivable/(payable) (also known as Agent Billing and Collection (ABC) receivable/(payable)), gas in storage, and working cash allowance.

Table 1
Allowance for Working Capital - Average of Monthly Averages
2024 Test Year

Line No.	Particulars ($ millions)	2024	
1	Materials and Supplies	107.0	
2	Customer Security Deposits	(60.2)	
3	DCB Receivable/(Payable)	(5.1)	
4	Gas in Storage	648.4	
5	Working Cash Allowance (1)(2)	(133.1)	/u
6	Allowance for Working Capital	557.0	/u

Notes:
(1) Attachment 2.
(2) Working cash allowance is a product of transaction patterns throughout the year and is not an average of monthly averages amount.

6. Explanations related to the makeup of the 2024 Test Year Forecast allowance for working capital are set out below.

2. Harmonization of Allowance for Working Capital Components

7. As part of preparing the 2024 Test Year Forecast for rate base, Enbridge Gas noted a number of items within the allowance for working capital components of EGD and Union that required alignment/harmonization. The following section describes the proposal for an aligned and harmonized list of items to be included as part of Enbridge Gas's allowance for working capital the 2024 Test Year and going forward.

2.1. Rebillable Accounts Receivable (AR)

8. Rebillable AR are capital project expenses that the utility expects to be reimbursed for from third parties, typically other utility companies or municipalities. This occurs for example in instances where a third-party requires a pipe to be moved, Enbridge Gas will incur the associated cost, and "rebill" the third-party at a future date recognizing a receivable. Historically, EGD included rebillable AR as an allowance for working capital component within rate base to reflect the carrying charge of the funds expended until they are reimbursed. Union has not historically included rebillable AR as a component of the allowance for working capital.

9. As an alignment initiative in 2019, Enbridge Gas elected to no longer recognize EGD rebillable AR as a component of the allowance for working capital for administrative ease, in line with Union's non-inclusion. This change results in a benefit to ratepayers through a reduction to the allowance for working capital and rate base. Enbridge Gas implemented this as part of the determination of 2019 Rate Base and resulting ESM results[1].

[1] EB-2020-0134.

2.2. Materials and Supplies

10. As part of ongoing operations and maintenance, Enbridge Gas maintains materials and supplies inventory that includes pipe for replacement purposes, compressor parts, meter and regulator parts, and other general materials. On hand inventory for these items is required as each typically have a long lead time to procure, are vital to the continued operations of facilities, are used for emergency replacement, and/or require customization.

11. Prior to 2019, Union allocated materials and supplies inventory to unregulated storage in proportion to unregulated storage plant as a percentage of total plant. Throughout the 2019 to 2023 deferred rebasing term, Enbridge Gas continues to apply a portion of materials and supplies inventory to its unregulated business leaving only the utility portion in its allowance for working capital component for the Union rate zones. Prior to 2019, EGD did not allocate any of its materials and supplies inventory to unregulated storage operations, which continued through the deferred rebasing term for the EGD rate zone.

12. In order to align the treatment of materials and supplies inventory in Enbridge Gas's 2024 Test Year allowance for working capital, the Company proposes to adopt the Union approach and allocate a portion of total Enbridge Gas materials and supplies to unregulated storage operations and exclude this portion from Enbridge Gas's utility allowance for working capital. Materials and supplies are allocated to unregulated storage operations using a composite rate, based on the proportion of the Company's unregulated operating & maintenance (O&M) expenses relative to total O&M expenses.

2.3. Prepaid Expenses

13. Both EGD and Union, prior to 2019, included an allowance for working capital component for prepaid expenses including property taxes and insurance. Enbridge Gas continued to do so during the deferred rebasing term. However, as of the 2024 Test Year, Enbridge Gas will no longer have an allowance for working capital component related to prepaid property tax and insurance, and instead these items are factored into the Company's working cash allowance. Details are provided below.

Prepaid Property Tax

14. As discussed in the Lead-Lag Study, provided at Exhibit 2, Tab 3, Schedule 2, Attachment 1, Section 4.3., page 16, Enbridge Gas has determined that it is appropriate to include the cash flow impacts of property tax payments in the working cash allowance calculation, as opposed to including them as discrete allowance for working capital components as EGD and Union have historically. This treatment adopted within the working cash allowance calculation allows for administrative ease, further aligns Enbridge Gas with other utilities and recognizes property tax as a key expense lead impacting cash requirements. Additionally, it provides an appropriate reflection of actual cash flow impacts because actual cash payments are used as opposed to an average of monthly averages. Therefore, the property tax amounts have been removed as a separate component in the allowance for working capital calculation and are now factored into the working cash allowance calculation provided at Attachment 2.

Prepaid Insurance

15. As a result of the centralization of shared services and other costs, the Central Functions Cost Allocations Methodology (CFCAM) has eliminated the prepayment

aspect of insurance expense for Enbridge Gas. As such, insurance expense, as an element of CFCAM other O&M, is reflected in the working cash allowance along with other CFCAM amounts. Please see the Lead/Lag Study details in Exhibit 2, Tab 3, Schedule 2 for details on the inclusion of insurance expense.

2.4. DCB Receivable/(Payable)

16. DCB is an administrative service offered by Enbridge Gas that provides energy marketers (brokers) and others the ability to bill end-use customers for their supply on Enbridge Gas's bill. A discussion of DCB service is provided at Exhibit 1, Tab 14, Schedule 3.

17. The DCB service provided by EGD has been considered a non-utility activity and, as such, rate setting has not been subject to OEB review and approval. This approach differed from Union's DCB program, which has been considered a utility activity. As such, Union has included the cash flow difference between receivables and payables associated with the program as a component of its utility allowance for working capital.

18. As provided at Exhibit 1, Tab 14, Schedule 3, to align the EGD and Union rate zones programs, Enbridge Gas proposes to treat harmonized DCB services as a utility service as of the 2024 Test Year. Consistent with Union's approach, Enbridge Gas will include DCB receivables and payables in the allowance for working capital.

19. As part of Enbridge Gas's DCB program, the broker enters into an agreement with Enbridge Gas to deliver a consistent volume of gas throughout the year. Customer consumption differs from the broker deliveries primarily due to seasonality/weather impacts the change in the number of Direct Purchase (DP) customers monthly,

resulting in differences between the amount of gas delivered by brokers compared to the amount of gas consumed by customers.

20. As part of the agreement with the broker, Enbridge Gas agrees to remit payment for the full value of the gas delivered monthly. On a monthly basis, the broker delivers gas onto the system at an even increment, and the customer pays for gas usage based on consumption. The difference between the two is either banked gas owed to or from the broker. The difference between cash payments remitted to the broker and the amounts billed and collected from customers is funded through allowance for working capital.

21. Contract parameters including start date will have an impact on the overall net monthly DCB Receivable/(Payable) balance for Enbridge Gas. The contract parameters for each DCB customer will vary and include different start and end dates which typically span over successive calendar periods. Therefore, on a monthly basis, the aggregate of DCB balances can represent a mix of receivables and payables pertaining to each DCB customer, however netted in total as either a receivable or payable to Enbridge Gas, which will impact the Company's allowance for working capital requirements.

2.5. Direct Purchase Balancing Gas and Gas in Storage

22. Historically both EGD and Union have included gas in storage as a component of allowance for working capital. Further, both utilities have included DP balancing gas as part of allowance for working capital, however the basis for inclusion for each of the EGD and Union rate zones has differed historically and through the 2019 to 2023 deferred rebasing term.

23. Enbridge Gas holds gas in storage to manage variations in Bundled DP customers' seasonal loads in both the EGD and Union rate zones. For the EGD rate zone, the value of this gas has historically been included in the overall gas in storage value. These amounts are valued at EGD's Purchased Gas Variance Account (PVGA) reference price and are revalued quarterly as part of Quarterly Rate Adjustment Mechanism (QRAM) changes. For the Union rate zones, DP balancing gas has been recorded as a fixed asset on the balance sheet and valued at a historical weighted average cost of gas, the balance of which is included in Enbridge Gas's allowance for working capital as a separate component on its own.

24. To align and harmonize the treatments as of January 1, 2024, Enbridge Gas is proposing the following, and has reflected the impacts as such in the Company's 2024 Test Year allowance for working capital forecast:
    a) Align to the current EGD rate zone treatment and recognize DP balancing gas as part of gas in storage and value based on Enbridge Gas's reference price. This will result in Enbridge Gas classifying the Union rate zone DP balancing gas as part of gas in storage and revaluing the January 1, 2024, balance based on the proposed weighted average reference price (Please see Exhibit 4, Tab 2, Schedule 2 for further details on the proposed common reference price).
    b) As a result of reclassifying the Union DP balancing gas to gas in storage, a revaluation impact will be recognized at January 1, 2024, which is proposed to be included in Enbridge Gas's PVGA account. See below for further details.

Regulatory Considerations

25. As part of Union's 2002 Rates Settlement Agreement[2], parties agreed to Union's proposal to apply inventory revaluation only to the portion of gas in inventory that was related to the needs of sales service customers, separating the gas required to balance DP customers and discontinue revaluation of the asset. Per Union's 2002 Rates Application, the reasons for this proposal were as follows:
    a) The system had a significant amount of gas in inventory to meet the requirement to provide balancing for Bundled DP customers;
    b) Inventory revaluation on amounts pertaining to all gas (sales service and DP balancing gas) were cleared to sales service customers only, resulting in sales service customers potentially paying more or less than the cost of gas; and
    c) There were dramatic changes in gas prices during 2000 and 2001, and Union expected more sales service customers to shift to DP, and therefore significant inventory revaluation would be recovered from only a smaller number of sales service customers.[3]

26. Since the time of the decision to segregate Union's DP balancing gas, there has been a significant decline in the number of customers taking DP services[4]. This is primarily a result of less volatile market pricing for natural gas in more recent years. As a result, the required level of DP balancing gas that Union has maintained to balance DP customers draft positions has declined significantly from 28.9 PJ in 2001 to 13.5 PJ at the end of 2021, a 53% decrease. As the requirement to balance DP customers has decreased over time, transfers of the DP balancing gas back to

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[2] RP-2001-0029.
[3] RP-2001-0029, Union Gas 2002 Rates and Customer Review Settlement Agreement, Section 12, Inventory Revaluation Methodology.
[4] Per Exhibit 3, Tab 3, Schedule 1, Attachment 1, 2013 EGD and Union combined Bundled DP customer count was 0.6 million, as of 2021, the Enbridge Gas Bundled DP customer count dropped to 0.1 million.

sales service gas in storage have resulted in revaluation impacts that have either been debited or credited to Union's PGVA and disposed of accordingly.

27. Further, subsequent to the decision noted above, Union received approval to implement DP balancing checkpoints (Please see Exhibit 8, Tab 4, Schedule 3 for details of checkpoint balancing). Effectively, as of 2004 implementation, the check point balancing has ensured that DP customers' Banked Gas Accounts (BGA) balances remain approximately at planned levels that Union can manage appropriately and effectively through regular gas purchases that address the needs of all utility customers.

28. As provided at Exhibit 8, Tab 4, Schedule 3, pages 5 and 23, except for any proactive management by customers through balancing transactions, Enbridge Gas manages all other load balancing needs for all Bundled DP and sales service customers in the EGD zone (and similarly in the Union rate zones). Actual costs incurred by Enbridge Gas to provide load balancing is recovered from all bundled DP and sales service customers. Enbridge Gas considers the planned BGA curves for all Bundled DP customers, as well as demand requirements for sales service customers, to ensure that it has enough gas in its gas supply and storage plans to meet the overall requirement through winter and leaving enough room in storage at the end of the summer. The cost of this base load balancing is recovered from all bundled DP and sales service customers in rates.

29. Reclassifying the Union DP balancing gas fixed asset to gas in storage provides alignment for Enbridge Gas, is more simplistic from an administrative perspective, eliminating the need to segregate any portion of gas in storage on Enbridge Gas's balance sheet, and allows for alignment, consistency and simplicity on Enbridge

Gas's balance sheet and in its allowance for working capital components. The alignment within gas in storage ensures that the gas in storage balance going forward will meet the load balancing needs for both sales service and DP customers. Finally, the alignment proposed in this evidence provides consistency between the operational principles and policies and the financial treatments and impacts of services offered to sales service and DP customers.

30. For the 2022 gas year, the Enbridge Gas forecast for DP balancing gas required in the Union rate zones is 13.5 million GJ. This assumption has not changed since 2020. The fixed asset value at the historical weighted average is currently $59.5M ($4.404/GJ x 13.5 million GJ). Assuming the balance moves to gas in storage January 1, 2024, the January 1 OEB-approved reference price would be used to revalue the asset.

31. Using the proposed weighted average reference price, the total inventory value moved to gas in storage would be $71.7 million ($5.309/GJ[5] x 13.5 million GJ). The resulting variance between the Union rate zones fixed asset in current state versus revaluation in gas in storage is $11.7 million. At January 1, 2024, the journal entry required to reflect the reclassification and revaluation would be:

Dr. Gas in Storage	$71.7 million	
Cr. Long Term Assets		$59.5 million
Cr. PGVA (payable to ratepayers)		$11.7 million

The resulting inclusion of the $71.7 million in gas in storage forms part of the overall inclusion of gas in storage in Enbridge Gas's gas in storage on an average of averages basis for the 2024 Test Year.

[5] Exhibit 4, Tab 2, Schedule 2.

2.6. Working Cash Allowance Calculation

32. As provided in Section 2.1, since 2019, Enbridge Gas has been filing a working cash allowance balance as part of the allowance for working capital representative of the combination of the two EGD and Union calculations that have been in effect since the last time each utility rebased. The respective working cash allowance calculations are underpinned by each of EGD's and Union's OEB-approved lead/lag studies.

33. The calculation for working cash allowance proposed for Enbridge Gas beginning in the 2024 Test Year and the basis for the amount included in the 2024 Test Year allowance for working capital is based on applying the net lag days as identified in Enbridge Gas's Lead/Lag Study, provided at Exhibit 2, Tab 3, Schedule 2, to each of the applicable components of expense leads. These include cost of gas, operations and maintenance, property taxes, interest and income tax expense, as well as factoring in net lag impacts of harmonized sales tax (HST) and federal carbon.

3. Historical and Forecast Comparatives

34. Table 2 provides an overview of the allowance for working capital and the year-over-year change in the allowance for working capital for Enbridge Gas over the deferred rebasing term as well as the 2024 Test Year.

Table 2
Allowance for Working Capital - Variance Analysis - Average of Monthly Averages

Line No.	Particulars ($ millions)	Utility	2019 Actual (a)	2020 Actual (b)	2021 Actual (c)	2022 Estimate (d)	2023 Bridge Year (e)	2024 Test Year (f)	
1	Materials and Supplies	EGI	74.9	82.2	92.5	93.1	101.5	107.0	
2	Customer Security Deposits	EGI	(91.0)	(81.8)	(68.9)	(67.7)	(64.0)	(60.2)	
3	Prepaid Expenses	EGI	5.6	3.1	4.7	4.8	4.8	0.0	
4	DCB Receivable/(Payable)	EGI	(30.2)	(22.3)	(15.5)	(15.3)	(17.0)	(5.1)	
5	Balancing Gas	EGI	56.2	59.5	59.5	59.5	59.5	0.0	
6	Gas in Storage	EGI	522.0	487.5	594.7	776.1	580.6	648.4	
7	Working Cash Allowance	EGI	24.9	23.0	20.9	5.4	24.0	(133.1)	/u
8	Total		562.3	551.2	687.7	855.9	689.4	557.0	/u
	Variances								
9	Materials and Supplies			7.3	10.3	0.6	8.4	5.5	
10	Customer Security Deposits			9.2	12.9	1.2	3.7	3.8	
11	Prepaid Expenses			(2.5)	1.6	0.1	0.0	(4.8)	
12	DCB Receivable/(Payable)			7.9	6.8	0.2	(1.7)	11.9	
13	Balancing Gas			3.3	(0.0)	0.0	0.0	(59.5)	
14	Gas in Storage			(34.5)	107.2	181.4	(195.5)	67.8	
15	Working Cash Allowance			(1.9)	(2.1)	(15.5)	18.6	(157.1)	/u
16	Variance of Working Capital to Prior Year			(11.1)	136.5	168.2	(166.5)	(132.4)	/u

35. The average balance of materials and supply inventory has continuously increased over the 2019 to 2021 years and this trend is expected to continue through the remainder of the deferred rebasing term. This is primarily a result of increases in material costs which drive up the average cost of materials and supplies inventory. Further, Enbridge Gas has planned for larger lead times of inventory purchases resulting from supply shortages experienced in 2020 to 2022. For the forecast years 2022 to 2024, Enbridge Gas is expecting an approximate 5% annual increase in

average cost as there continues to be an expectation that prices will continue to rise with inflation and the Company continues to plan for supply shortages.

36. The average balance of customer security deposit holdings consistently decreased over the deferred rebasing term because of Enbridge Gas collecting fewer security deposits from new distribution customers while existing deposits continued to expire annually and were credited back to customers. As well, held on account security deposits were applied against amounts owing by distribution customers with overdue accounts[6]. This trend is expected to continue through 2024 and beyond.

37. The average balance of prepaid expenses held relatively steady over the deferred rebasing term. However, the decrease in the prepaid expense category above in the 2024 Test Year is offset by the inclusion of prepaid expenses in the allowance for working cash calculation. Please see Exhibit 2, Tab 3, Schedule 2 for further details of this proposed treatment.

38. The average balance of the DCB payable (also previously known as the ABC payable) has been consistently decreasing over the deferred rebasing term as a result of a decline in the number of DP customers and brokers electing the service. As noted above, these balances represent the average monthly net financial position of all DCB customers in relation to the variance between cumulative deliveries and consumption of those customers. Through the deferred rebasing term these balances pertained to only Union DCB customers since EGD DCB customers were considered to be non-utility. As of 2024 Enbridge Gas is proposing that all DCB customers and associated services be considered utility and therefore the average DCB balances within the allowance for working capital represent the

[6] Per Gas Distribution Access Rules, Amended March 1, 2020, Section 9.2.30.

combined forecast balances of EGD and Union. The resulting decrease in the average balance is a result of the average balances pertaining to EGD customers being in a debit position versus Union customers, on average, being in a credit position.[7]

39. The average balance of balancing gas has held relatively steady over the deferred rebasing term. The decrease in this category for the 2024 Test Year is resulting from reallocating the balancing gas to be an inclusion in gas in storage in 2024 and going forward.

40. The average balance of gas in storage inventory is heavily driven by changes in the average reference price during the year and can also be impacted by the average - volume of gas in storage held year-over-year. The fluctuations in gas in storage over the deferred rebasing term and through the forecast years is resulting primarily from changes in the average reference price. The significant decrease in gas in storage costs between 2019 and 2020 was driven by a lower average reference price, whereas 2021 and 2022 saw large increases in the average reference price. For 2023 the average reference price is set at the April 2022 reference price which was lower than the 2022 estimated average reference price. For the 2024 Test Year, the increase over the 2023 Bridge Year is a result of the inclusion of balancing gas inventory and is based on the Enbridge Gas proposed weighted average reference price provided at Exhibit 4, Tab 2, Schedule 2.

41. Working cash allowance has held relatively stable over the deferred rebasing term and has been based on the combination of the calculations for EGD and Union

[7] Contract start and end dates for DCB customers impact the average of monthly averages balances during a calendar year.

underpinned by respective lead/lag study results. The fluctuation in forecast to the 2024 Test Year is primarily resulting from the inclusion of the cash flow impacts of the federal carbon customer-related charges in the working cash allowance calculation and the application of the new lead/lag days as per the proposed Lead/Lag Study provided at Exhibit 2, Tab 3, Schedule 2.

Allowance for Working Capital Summary - Average of Monthly Averages

Line No.	Particulars ($ millions)	Utility	2013 OEB-Approved	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Materials and Supplies	EGD	31.9	40.6	35.5	38.9	37.7	36.2	38.3
2	Customer Security Deposits	EGD	(68.7)	(63.7)	(61.4)	(59.8)	(56.5)	(47.2)	(44.8)
3	Prepaid Expenses	EGD	1.8	1.2	1.3	1.9	1.7	1.4	0.6
4	Accounts Receivable Rebillable Projects	EGD	1.3	4.1	1.3	1.3	1.4	1.4	1.4
5	Gas in Storage	EGD	248.4	320.0	402.7	481.1	354.4	372.0	415.4
6	Working Cash Allowance (1)	EGD	1.8	(2.6)	6.0	10.3	(0.7)	(0.9)	1.7
7	Total - EGD		216.7	299.6	385.4	473.7	338.0	362.9	412.6
8	Materials and Supplies	Union	29.6	28.6	28.2	26.8	29.0	31.8	32.2
9	Customer Security Deposits	Union	(48.2)	(35.6)	(35.8)	(38.6)	(39.4)	(41.0)	(46.5)
10	Customer Deposit Interest	Union	(0.8)	(0.4)	(0.3)	(0.2)	(0.1)	(0.1)	(0.1)
11	Prepaid Expenses	Union	5.0	5.0	5.1	5.6	4.9	2.2	1.2
12	ABC Receivable (Payable)	Union	(44.9)	(31.0)	(32.3)	(27.9)	(13.0)	(17.1)	(28.1)
13	Balancing Gas	Union	73.0	68.4	65.9	68.9	67.1	65.7	55.7
14	Gas in Storage	Union	163.1	142.7	174.3	180.3	184.5	146.5	110.1
15	Working Cash Allowance (1)	Union	20.0	20.6	20.7	20.7	21.2	22.5	24.0
16	Total - Union		196.8	198.2	225.8	235.5	254.1	210.5	148.5

Notes:
(1) Working cash allowance is a product of transaction patterns throughout the year, and is not an average of monthly averages amount.

Allowance for Working Capital Summary - Average of Monthly Averages

Line No.	Particulars ($ millions)	Utility	2019 Actual	2020 Actual	2021 Actual	2022 Estimate	2023 Bridge Year	2024 Test Year	
			(a)	(b)	(c)	(d)	(e)	(f)	
1	Materials and Supplies	EGI	74.9	82.2	92.5	93.1	101.5	107.0	
2	Customer Security Deposits	EGI	(91.0)	(81.8)	(68.9)	(67.7)	(64.0)	(60.2)	
3	Prepaid Expenses	EGI	5.6	3.1	4.7	4.8	4.8	0.0	
4	DCB Receivable (Payable) (1)	EGI	(30.2)	(22.3)	(15.5)	(15.3)	(17.0)	(5.1)	
5	Balancing Gas	EGI	56.2	59.5	59.5	59.5	59.5	0.0	
6	Gas in Storage	EGI	522.0	487.5	594.7	776.1	580.6	648.4	
7	Working Cash Allowance (2)	EGI	24.9	23.0	20.9	5.4	24.0	(133.1)	/u
8	Total		562.3	551.2	687.7	855.9	689.4	557.0	/u

Notes:
(1) Union rate zones DCB Receivable (Payable) from 2019 to 2023. EGI DCB Receivable (Payable) in 2024.
(2) Working cash allowance is a product of transaction patterns throughout the year, and is not an average of monthly averages amount.

Working Cash Allowance
2024 Test Year

Line No.	Particulars ($ millions)	Revenue Lag Days	Expense Lead Days	Net Lag Days (1)	2024 Expenses	2024 Allowance	
				(c) = (a-b)			
		(a)	(b)	(1)	(d)	(e) = (a x c) /365	
1	Cost of Gas	39.5	39.2	0.3	3,228.0	2.7	
2	Operations and Maintenance (O&M) Costs	39.5	44.6	(5.1)	1,046.0	(14.6)	/u
3	Property Tax Expense	39.5	(17.5)	57.0	127.2	19.9	
4	Interest Expense	39.5	11.5	28.1	420.0	32.3	/u
5	Income Tax Expense	39.5	15.2	24.3	43.8	2.9	/u
					4,864.9	43.2	/u
6	Harmonized Sales Tax (on Cost of Gas and O&M)			6.3	492.2	8.5	/u
7	Federal Carbon - Customer Levy			(24.3)	2,775.3	(184.8)	
8	Total Working Cash Allowance					(133.1)	/u

Note:
(1) Lead-Lag Study, Exhibit 2, Tab 3, Schedule 2.

EGI Allowance for Working Capital Components - Month End Balances and Average of Monthly Averages
2024 Test Year

Line No.	Particulars ($ millions)	Materials and Supplies	DCB Receivable/ (Payable)	Customer Security Deposits	Gas in Storage	Working Cash Allowance (1)	Total	Gas in Storage Volumes (10^3m^3)	
		(a)	(b)	(c)	(d)	(e)	(g)	(h)	
1	January 1	100.6	(10.0)	(61.2)	819.7	(133.1)	716.1	4,610,084.3	/u
2	January 31	102.1	19.2	(62.5)	663.4	(133.1)	589.1	3,783,963.0	/u
3	February	102.6	(5.5)	(62.4)	520.0	(133.1)	421.5	2,829,997.7	/u
4	March	104.1	(38.9)	(62.5)	311.4	(133.1)	180.9	1,638,258.4	/u
5	April	106.6	(40.5)	(62.4)	251.1	(133.1)	121.7	1,293,392.8	/u
6	May	106.9	(41.9)	(63.3)	331.4	(133.1)	200.1	1,807,154.4	/u
7	June	108.3	(43.3)	(58.4)	509.0	(133.1)	382.6	2,857,696.2	/u
8	July	110.0	(16.0)	(58.6)	665.5	(133.1)	567.8	3,853,051.2	/u
9	August	112.7	2.0	(58.7)	776.7	(133.1)	699.5	4,600,600.5	/u
10	September	107.3	12.3	(58.0)	933.2	(133.1)	861.7	5,560,848.6	/u
11	October	109.1	38.0	(58.0)	1,021.7	(133.1)	977.7	6,107,818.0	/u
12	November	110.9	44.2	(58.0)	955.2	(133.1)	919.2	5,711,840.3	/u
13	December	105.9	28.9	(57.4)	865.1	(133.1)	809.3	5,110,821.3	/u
14	Average of Monthly Averages	107.0	(5.1)	(60.2)	648.4	(133.1)	557.0	3,742,089.5	/u

Note:
(1) Working cash allowance is a product of transaction patterns throughout the year, and is not an average of monthly averages amount.

WORKING CASH ALLOWANCE
LEAD-LAG STUDY
JASON VINAGRE, MANAGER REGULATORY ACCOUNTING

1. The purpose of this evidence is to request OEB approval of Enbridge Gas's 2021 Lead-Lag Study. The Lead-Lag Study (Study) supports the lead-lag days that underpin the 2024 Test Year Forecast working cash allowance. The Lead-Lag Study was completed by Enbridge Gas in 2022 and is based on 2021 actual utility results, the most recent full year of actual data available. The approach and results are set out in the Enbridge Gas Inc - 2021 Lead-Lag Study (Study) provided at Attachment 1.

2. This evidence is organized as follows:
    1. Background
    2. Summary of Results

1. Background

3. Working cash allowance, an element within the allowance for working capital component of utility rate base, is the amount of cash available (or requirement needed) to a utility to fund operations after considering the timing of typical revenue collections from customers and bill payments to vendors and agencies.

4. The timing difference between funds available and funds required is referred to in terms of lead and lag days. The revenue lag days is the amount of time between when a customer receives service from the utility, and when customer payments are received by the utility. The expense lead days is the amount of time between when a utility receives service and when the utility pays for that service. The total

revenue lag days are then compared against each of the expense lead days, the difference between the two is referred to as the net days. The net days can be expressed as either positive or negative. A positive net represents a cash shortfall, which would result in a positive addition to the working cash allowance. A negative net represents a cash surplus which would result in a reduction to the working cash allowance.

5. The net days are used to calculate the working cash allowance by taking the net days divided by 365 multiplied by each expense ($). These are then added together to calculate the total working cash allowance, which is then included as an input in the working capital calculation.

2. Summary of Results

6. Enbridge Gas reviewed the previous EGD[1] and Union[2] lead-lag studies, and harmonized the methodologies, to be effective as of the 2024 Test Year. Enbridge Gas updated its study using 2021 actuals, reviewing the combined revenue lag, including service, billing and collection lags for each main grouping of customers. As well, the combined expense leads were reviewed, including the service and payment leads for each major grouping of expenditure. A comparison was also completed from 2021 actuals back to 2013 OEB-approved for each respective company. The results of this review, the harmonization, changes in approach, and new proposed items are set out in the Study. Table 1 provides the lag days results contained in the Study along with the resulting calculation of the 2024 Test Year working cash allowance.

[1] EB-2011-0354, Exhibit B3, Tab 1.
[2] EB-2011-0354, Exhibit B3, Tab 1; Response to Exhibit I.Energy Probe.1.Issue B7, Schedule 7.1.

Table 1
2024 Working Cash Allowance Requirements

Line No.	Particulars ($ millions)	Revenue (Days) (1)	Expense (Days)		Net (Days)	Expenses ($) (7)	Working Cash Allowance ($)	
		(a)	(b)		(c) = (a-b)	(d)	(e) = (d x c)/365	
1	Gas Purchases	39.5	39.2	(2)	0.3	3,228.0	2.7	
2	Operations and Maintenance (O&M) Costs	39.5	44.6	(3)	(5.1)	1,046.0	(14.6)	/u
3	Property Tax Expense	39.5	(17.5)	(4)	57.0	127.2	19.9	
4	Interest Expense	39.5	11.5	(5)	28.1	420.0 (8)	32.3	/u
5	Income Tax Expense	39.5	15.2	(6)	24.3	43.8	2.9	/u
6	Subtotal				33.9	591.0	55.1	/u
7	Subtotal					4,865.0	43.2	/u
8	HST				6.3		8.5	/u
9	Total - including HST						51.7	/u
10	Federal Carbon (Customer Portion)				(24.3)	2,775.3	(184.8)	
11	Total - including Federal Carbon						(133.1)	/u

Notes:
(1) Exhibit 2, Tab 3, Schedule 2, Attachment 1, Table 3-1
(2) Exhibit 2, Tab 3, Schedule 2, Attachment 1, Table 4-1
(3) Exhibit 2, Tab 3, Schedule 2, Attachment 1, Table 4-2
(4) Exhibit 2, Tab 3, Schedule 2, Attachment 1, Table 4-5
(5) Exhibit 2, Tab 3, Schedule 2, Attachment 1, Table 4-6
(6) Exhibit 2, Tab 3, Schedule 2, Attachment 1, Table 4-7
(7) Exhibit 6, Tab 1, Schedule 2, Attachment 1
(8) Exhibit 5, Tab 2, Schedule 1, Attachment 6

7. Enbridge Gas is forecasting a 2024 working cash allowance of negative $133.1 million. Overall, Enbridge Gas has operating expenses including HST that require a working cash allowance of $51.7 million throughout the year, however, the availability of funds, $184.8 million, from the Federal Carbon program (prior to remitting monthly as required) results in a net cash surplus that can be used to fund operation needs. /u /u

8. The results of the 2022 study were compared to the previously filed and approved Lead/Lag Days of EGD and Union. The comparison is summarized in Table 2, and further details are provided at Attachment 1.

2.1. Operating Revenue Lag

9. The revenue lag of 39.5 days for Enbridge Gas is between the previous EGD lag of 42.2 days and Union lag of 38.1 days.

2.2. Gas Purchases Lead

10. The gas purchases lead of 39.2 days for Enbridge Gas is between the previous of 42.2 days for EGD and of 38.1 days for Union. The net gas purchase days of 0.3 in turn has an approximate impact of $2.7 million on the working cash allowance.

2.3. O&M Expense Lead

11. Enbridge Gas's O&M lead is comprised of two main elements: Compensation and Benefits, and Other O&M, which includes expenses related to, but not limited to, the procurement of outside services and allocated corporate shared services charges. The lead days related to compensation and benefits are tied to Enbridge Gas payroll cycles and withholding remittance due dates. The lead days for other O&M procured externally are tied to vendor payable due dates, while the lead days on corporate shared services costs allocated to Enbridge Gas are tied to the Enbridge

quarterly settlement cycle. Overall, the O&M lead of 44.6 days for Enbridge Gas is between the previous of 60.9 days for EGD and 20.8 days for Union. The net O&M days of (5.1) in turn has an approximate impact of ($14.6 million) on the working /u
cash allowance.

2.4. Property Tax, Interest, and Income Tax Expense Leads

12. Enbridge Gas is introducing the property tax, interest and income tax expense leads for the 2024 Test Year Forecast (new from previous studies) as part of recognizing that these are true cash operating expenses that are material to the working cash allowance. Further this introduction allows Enbridge Gas to align with other utilities[3] in Ontario that have included these items as components of their working capital calculations. On a combined weighted basis this results in net days of 33.9 and an approximate $55.1 million working cash allowance. /u

2.5. Sales Tax

13. Enbridge Gas collects and remits as well as pays and recovers sales taxes on payments from customers and to vendors. The net days of 6.3 for Enbridge Gas is between the net lag of 1.8 days for EGD and 12.9 days for Union. Using the 2024 Test Year forecasted amounts, this results in an approximate $8.5 million impact to /u
working cash allowance.

2.6. Federal Carbon Lead

14. The introduction of the Federal Carbon lead is reflective of the cash flow implications related to Enbridge Gas billing, collecting and then remitting the Federal Carbon charge. Enbridge Gas ultimately bills and collects the charges from

[3] Hydro One, EB-2021-0110, Exhibit C, Tab 5, Schedule 1; OPG, EB-2020-0290, Exhibit B1, Tab 1, Schedule 2; Toronto Hydro, EB-2018-0165, Exhibit 2A, Tab 3, Schedule 2.

ratepayers and then remits the following month. This results in net days from collections and remittances of 24.3 for Enbridge Gas. This results in an approximate $184.8 million negative working cash allowance.

15. Enbridge Gas is also subject to the carbon charge for the natural gas consumed at its facilities, which is reflected in the gas costs calculations.

Table 2
Lead/Lag Comparison to Previous OEB-Approved

Line No.	Particulars	Enbridge Gas 2024 Revenue Lag Days (Days)	Enbridge Gas 2024 Expense Lead Days (Days)	Enbridge Gas 2024 Net Lag Days (Days)	EGD 2013 Revenue Lag Days (Days)	EGD 2013 Expense Lead Days (Days)	EGD 2013 Net Lag Days (Days)	Union 2013 Revenue Lag Days (Days)	Union 2013 Expense Lead Days (Days)	Union 2013 Net Lag Days (Days)
		(a)	(b)	(c) = (a-b)	(d)	(e)	(f) = (d-e)	(g)	(h)	(i) = (g-h)
1	Gas Purchases	39.5	39.2	0.3	42.2	38.2	4	38.1	38.8	(0.7)
2	Operations & Maintenance	39.5	44.6	(5.1)	42.2	60.9	(18.7)	38.1	20.8	17.3
3	Property Taxes	39.5	(17.5)	57.0	N/A	N/A	N/A	N/A	N/A	N/A
4	Interest Expense	39.5	11.5	28.1	N/A	N/A	N/A	N/A	N/A	N/A
5	Income Taxes	39.5	15.2	24.3	N/A	N/A	N/A	N/A	N/A	N/A
6	HST			6.3			1.8			12.9
7	Federal Carbon			(24.3)			N/A			N/A

Note:
(1) N/A indicates newly added lead/lag categories that were not included in prior EGD and Union lead/lag studies.

2021 Lead-Lag Study

Enbridge Gas Inc.

August 2022

Table of Contents

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2. Key Concepts
3. Revenue Lags
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1. Introduction

The OEB's Filing Requirements for Natural Gas Rate Applications, require a utility that is proposing to include a working cash allowance in rate base to support that request with a lead/lag study. Enbridge Gas Inc. (Enbridge Gas or EGI) has conducted a lead/lag study internally based on 2021 actual utility results to determine its working cash allowance needs for the rebasing term beginning January 1, 2024.

Working cash allowance, an item within the allowance for working capital component of utility rate base, reflects the average amount of funds required (or surplus funds available) to finance the day-to-day operations of a regulated utility, to pay for goods and services prior/subsequent to receiving revenues from customers. In simpler terms working cash is the difference between funds required and funds available.

The lead/lag study examines the difference between the revenue lag and the expense lead. The revenue lag is the time between when customers receive their service and the date when the customers' payments are received by the utility. The expense lead is the time between when the utility receives goods or services from its vendors and agencies and the date when it pays for those goods or services. Leads and lags are measured in days and are generally dollar weighted. The difference between the total expense leads and the total revenue lags is the net lag. A net lag number greater than zero indicates a cash 'shortfall' position, while a net lag number less than zero indicates a cash 'surplus' position. The dollar-weighted net lag days are then divided by 365 and multiplied by the annual test year cash expenses to determine the working cash allowance required for operations. This forecast of working cash is included in the allowance for working capital that is factored into the utility's rate base calculations.

Enbridge Gas has harmonized its methodology for the 2021 study using both Union Gas (Union) and Enbridge Gas Distribution's (EGD) previously approved studies (filed and approved as part of their 2013 rate cases[1]) as a starting point. The methodologies used by the utilities were similar and to the extent that changes to the previously approved methodologies or calculations were required to conduct a harmonized Enbridge Gas study for 2021, they have been noted in this report. The results of the study completed in 2022 are intended to be implemented and effective January 1, 2024 and will underpin Enbridge Gas's working cash allowance forecast for the 2024 Test Year.

[1] EB-2011-0354, Exhibit B3, Tab 1; Response to Exhibit I.Energy Probe.1.Issue B7, Schedule 7.1, (EGD); EB-2011-0210, Exhibit B1, Tab 8 (Union).

Table 1-1

Summary of Lead/Lag Results

Line No.	Particulars (Days)	2021 EGI Total Amount[2]	2021 EGI Lead/Lag (Days)	2021 EGI Weighted Dollar Days Amount
	Revenue Lags:			
1	Gas Sales & Distribution	4,480,600	39.7	177,684,313
2	Storage and Transportation	148,000	35.1	5,201,629
3	Other Revenue	49,100	39.8	1,954,180
4	Overall Operating Revenue Lag	4,677,700	39.5	184,840,122
5				
	Cost of Service Expense Leads:			
6	Gas Cost Lead	2,110,600	39.2	82,811,869
	Operation and Maintenance Lead:			
7	Compensation & Benefits	378,430	41.4	15,670,192
8	Other O&M	537,670	46.9	25,195,055
9	Overall O&M Expense Lead	916,100	44.6	40,865,246
10	Property Tax Expense	116,100	(17.5)	(2,031,750)
11	Interest Expense	380,000	11.5	4,352,490
12	Income Tax Expense	43,100	15.2	655,120
13	Total Expenditures Lead	3,565,900	35.5	126,652,975
14	Net HST Lag		6.3	
15	Net Carbon Lag		(24.3)	

[2] EGI's 2021 balances in this study do not reflect adjustments made between regulated and unregulated storage operations in Enbridge Gas's 2021 Utility Earnings and Disposition of Deferral & Variance Account Balances proceeding (EB-2022-0110), as filed on September 2, 2022.

2. Key Concepts

The following section outlines key concepts used throughout this report to assess the cash working capital requirements of Enbridge Gas's business. The key concepts that were applied include: the mid-point approach, dollar weighting, statutory approach and the econometric forecast model.

2.1 Mid-Point Method

When a service is provided to (or by) Enbridge Gas over a period of time, the service is deemed to have been provided (or received) evenly over the period, unless specific information regarding the provision (or receipt) of that service indicates otherwise. If both the service end date ("A") and the service start date ("B") are known, the mid-point of a service period can be calculated using Equation 2-1.

Equation 2-1

$$\text{Mid-Point} = \frac{(A - B) + 1}{2}$$

2.2 Dollar Weighting

As outlined in the OEB's filing requirements, the leads and lags have been dollar-weighted where data was available and where appropriate to reflect the flow of dollars more accurately. When calculating a dollar-weighted total for a revenue lag or expense lead item, the dollar amount for each line item is multiplied by its respective lead/lag day to calculate a weighted dollar day. The sum of the weighted dollar days is then divided by the sum of the total dollar amounts to calculate the weighted lead/lag days.

2.3 Due Dates

When calculating the revenue lags and expense leads, it is important to note that actual payment dates have not been utilized in all cases. There were instances throughout 2021 where due dates fell on weekends, holidays or there were special exemptions for payments due to the pandemic and Enbridge was able to delay payment or decided to make payment early. As these instances of delayed or early payments are not known for the rebasing term, it was decided to use the due dates instead of actual payment dates to calculate the lead/lag days. There are some instances where the due dates for payments are established by statute or by regulation. In these cases, the statutory date has been used in lieu of the date when payments were made. In instances where the due dates or statutory dates were used for modeling purposes, Enbridge Gas believes that this method is more appropriate because it most accurately reflects the typical timing of future payments.

2.4 Econometric Forecast Model

The revenue lag is comprised of service lag, billing lag and collection lag components. The collection lag is the time between when a bill is issued to the customer and when the customer pays for their bill. Collection lag is based on customer behavior and there are many factors that can affect when a customer makes their payment. Given this, there can be variability in the collection lag days from year to year. The forecasted collection day lag for 2024 is 21.5 days. The Collection Lag days is calculated by dividing the sum of Account Receivables by the sum of Billed Receivables. The ‘Accounts Receivable’ amount is a weighted calculation. For each billing cycle day, the amounts billed to our customers are multiplied by the number of days the amount remains outstanding. The ‘Billed Receivables’ amount is the sum of the total amount billed to our customers for the current month. To forecast what customers payment time would be in 2024, Enbridge Gas has used an econometric model to predict the Account Receivables and the Billed Receivables for 2024. The model developed is an auto-regressive equation for the General Service Accounts Receivable, General Service Billed Receivables, Large Volume Accounts Receivables, and Large Volume Billed Receivables. Below is an example of the model specification developed for the General Service Account Receivables (GSA):

$$GSA(t) = c + GSA(t-1) + AR(12)$$

Where:

- C : Intercept
- GSA (t) : Dependent variable to be predicted for month “(t)”
- GSA (t-1) : Actual GSA observation from month “(t-1)”
- AR(12) : Autoregressive error for previous 12 months
-

3. Revenue Lag

Enbridge Gas has three main sources of revenues that were considered: Gas Sales and Distribution, Storage and Transportation, and Other Operating Revenue. Table 3-1 sets out a summary of the Revenue lag days.

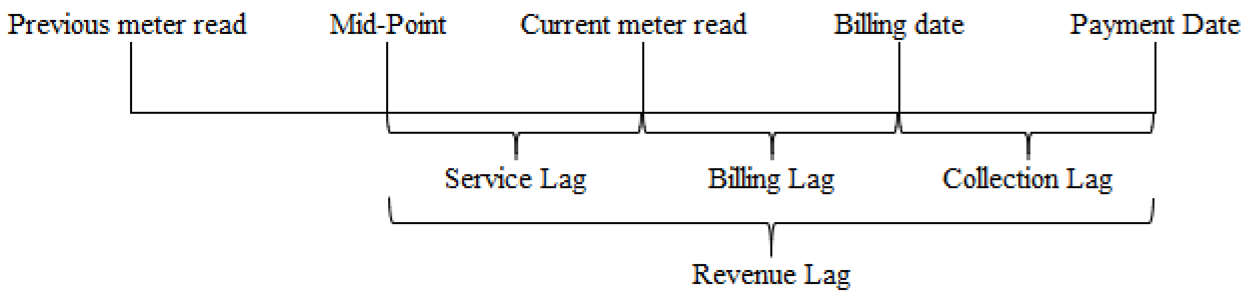
Table 3-1

Operating Revenue Lag Summary

Line No.	Particulars ($000s)	Amount	Revenue Lag (Days)	Weighted Dollar Days
		(a)	(b)	(c) = (a) x (b)
1	Gas Sales and Distribution	4,480,600	39.7	177,684,313
2	Storage and Transportation	148,000	35.1	5,201,629
3	Other Revenue	49,100	39.8	1,954,180
4	Total	4,677,700	39.5	184,840,122

Revenue lag consists of: Service Lag, Billing Lag, and Collection Lag which are illustrated in Schedule 3-1.

Schedule 3-1



3.1.1 Service Lag

Enbridge Gas's customers receive service on a continuous basis, which is measured monthly. For General Service customers, meters are read on a bi-monthly basis. For billing months where a meter reading is not performed, the Customer Information System (CIS) estimates the customers natural gas consumption. For remaining customers (Wholesale, Contract, Storage and Transportation) service is also delivered on a continuous basis, which is measured monthly, either based on contracted volumes or actual gas being delivered. The mid-point approach was used to determine the service lag for each period. For each service period, the mid-point is calculated using Equation 1-1. The total weighted amount was then divided by the total billed amount to calculate a weighted average service lag day. Using this approach, 15.2 days was calculated for the year.

3.1.2 Billing Lag

Enbridge Gas bills its customers on a monthly basis. The time between when the service date ends and the date of the bill is the billing lag. This was multiplied by the amount billed (by customer type) to calculate a weighted billing amount. The total weighted billing amount was then divided by the total amount billed to calculate a weighted average billing lag day. Using this approach, for Gas Sales and Distribution Revenue an average of 3.0 days was calculated for the year as set out in Table 3-2, and for Storage & Transportation Revenue an average of 3.7 days was calculated for the year as set out in Table 3-3.

3.1.3 Collection Lag

Prior to 2021, EGD and Union had different CIS', and with that calculated their collection lags using different approaches. EGD used actual customer payments to calculate the collection lag, and then forecasted the test year collection lag using an Econometric Model to address some variability in collection lag year over year. Union assumed that most customers paid on the due date, and then made an adjustment to the collection lag for overdue payments and used this as its forecast.

Enbridge Gas has now harmonized its CIS', therefore the collection lag calculation has been aligned. With the harmonization of the CIS', the data used to update the econometric model has been standardized for both EGD and Union customers allowing EGI to update the model for forecasting collection lag on a combined basis going forward.

Customer billing dates were compared to the customers payment dates to calculate the collection lag. This was multiplied by the amount due to calculate a weighted collection amount. The total weighted collection amount was then divided by the total amount due to calculate a weighted average collection lag day. Customers that did not pay their bills were not reflected in the weighted average collection amount; they are reflected as bad debt within the O&M section. The weighted average collection lag day is then input into the econometric model to update the forecasted days. Using this forecasted days, for Gas Sales and Distribution Revenue an average of 21.5 days was calculated for the year as set out in Table 3-2, and for Storage & Transportation Revenue an average of 16.2 days was calculated for the year as set out in Table 3-3.

Table 3-2

Summary of Gas Sales & Distribution Revenue Lag Results

Line No.	Particulars	Service Lag (Days)	Billing Lag (Days)	Collection Lag (Days)	Weighted Total (Days)
		(a)	(b)	(c)	(d)
1	General Service	15.2	3.0	21.6	39.8
2	Contract	15.2	3.0	20.3	38.5
3	Total Revenue Lag	15.2	3.0	21.5	39.7

Table 3-3

Summary of Storage & Transportation Revenue Lag Results

Line No.	Particulars	Service Lag (Days)	Billing Lag (Days)	Collection Lag (Days)	Weighted Total (Days)
		(a)	(b)	(c)	(d)
1	Storage & Transportation	15.2	2.7	16.4	34.3
2	Transactional Services	15.2	10.4	14.9	40.5
3	Total Revenue Lag	15.2	3.7	16.2	35.1

3.2 Gas Sales and Distribution Revenue

Gas sales consists of three main types of revenue, General Service, Wholesale and Contract. To calculate the revenue lag associated with gas sales, actual customer billing and payment records were analyzed from CIS transaction records. Table 3-4 sets out a summary of the Gas Sales and Distribution Revenue lag.

Table 3-4

Gas Sales and Distribution Revenue Lag

Line No.	Particulars ($000s)	Amount	Revenue Lag (Days)	Weighted Dollar Days
		(a)	(b)	(c) = (a) x (b)
1	General Service	4,122,835	39.8	163,923,786
2	Contract	357,765	38.5	13,760,527
3	Total	4,480,600	39.7	177,684,313

3.3 Storage and Transportation Revenue

To calculate the revenue lag for Storage and Transportation, the customer billing and payment information was analyzed from CIS transaction records. Table 3-5 sets out a summary of the Storage and Transportation lag days.

Table 3-5

Storage and Transportation Revenue Lag

Line No.	Particulars ($000s)	Amount	Revenue Lag (Days)	Weighted Dollar Days
		(a)	(b)	(c) = (a) x (b)
1	Storage and Transportation	127,317	34.3	4,363,028
2	Transactional Services	20,683	40.5	838,601
3	Total	148,000	35.1	5,201,629

3.4 Other Revenue

All of Enbridge Gas's Other Operating Revenue items were primarily related to General Service customers, therefore the 39.8 lag days calculated for General Service was applied to Other Operating Revenue items.

4. Expense Lead

Enbridge Gas has 6 main sources of expenses that were considered: Gas Costs, Compensation and Benefits, Other Operations and Maintenance (O&M), Property Tax, Interest Expense, and Income Tax. Expense lead consists of: Service Lead and Payment Lead which are illustrated in Schedule 4-1.

Schedule 4-1

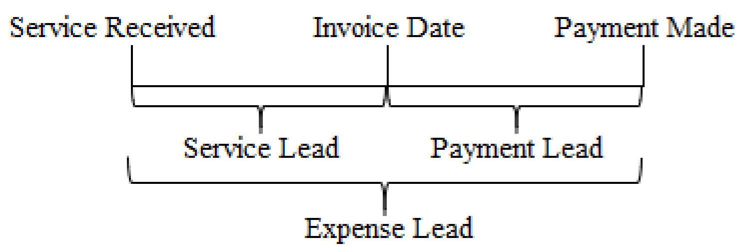


Table 4

Summary of Expense Lead Results

Line No.	Particulars	Service Lead (Days)	Payment Lead (Days)	Weighted Total (Days)
1	Gas Purchases	15.2	24.0	39.2
2	Compensation & Benefits	10.2	31.2	41.4
3	Other O&M	6.0	40.8	46.9
4	Property Tax Expense	182.5	(200.0)	(17.5)
5	Interest Expense	179.2	(167.7)	11.5
6	Income Tax Expense	15.2	-	15.2
7	Total Expense Lead	66.6	(36.5)	30.1

4.1 Gas Costs

Enbridge Gas purchases its natural gas and the associated transportation and storage requirements from various vendors to satisfy the supply needs required to serve its customers. For each vendor the service lead and the payment lead were analyzed using actual purchase records. For all vendors, the service period was determined to be monthly, and from there, using the mid-point approach, the service lead was calculated to be 15.2 days. Each vendor has different payment terms, ranging from 15-31 days, which represents the payment lead. Using the weighted average approach, an average of 39.2 days was calculated for the year. Table 4-1 sets out a summary of gas costs days by supplier.

Table 4-1

Gas Cost Lead

Line No.	Particulars ($000s)	Amount	Expense Lead (Days)	Weighted Dollar Days
		(a)	(b)	(c) = (a) x (b)
1	Transport	413,356	35.3	14,595,889
2	Commodity	1,689,699	40.2	67,925,887
3	Local Producers	2,649	35.2	93,232
4	Storage	4,897	40.2	196,860
5	Total	2,110,600	39.2	82,811,869

4.2 Operation & Maintenance (O&M)

Operation and Maintenance expenses consists of two main categories: Compensation & Benefits and Other O&M. On a total basis incorporating all O&M costs below, an average of 44.6 days was calculated for the year. Table 4-2 sets out a summary of the O&M lead days.

Table 4-2

O&M Expense Lead Summary

Line No.	Particulars ($000s)	Amount	Expense Lead (Days)	Weighted Dollar Days
		(a)	(b)	(c) = (a) x (b)
1	Compensation & Benefits	378,430	41.4	15,670,192
2	Other O&M	537,670	46.9	25,195,055
3	Total	916,100	44.6	40,865,246

4.2.1 Compensation and Benefits

Of all Enbridge Gas's Operations and Maintenance expenses, Compensation is one of the largest categories, and for this reason all payroll costs were analyzed using source records. Enbridge Gas has two main groups of payroll: hourly and salaried employees. Both groups are paid on bi-weekly payment cycles, however the service period included for each differs (hourly employees are paid the week following their pay period, salaried are paid during the second week of their pay period).

Employee Benefit costs is another large category of O&M and therefore all benefit costs were analyzed using source records. The main categories of employee benefits that were analyzed include:

- Employee Benefits
- Pension
- OPEB
- Legislative Benefits
- Other Benefits

Other benefits includes items such as Health & Wellness, Employee Assistance, Short Term Incentive Plan (STIP) and Long Term Incentive programs.

Each item was analyzed individually to calculate the service lead, which was monthly or 15.2 days. The payment lead, varied by expense type. Where applicable, the related statutory due date was applied for calculating their payment lead times.

Using the weighted average approach, an average of 41.4 lead days was calculated for the year. Table 4-3 sets out a summary of the compensation and benefits lead days.

Table 4-3

Compensation & Benefits Lead

Line No.	Particulars ($000s)	Amount	Expense Lead (Days)	Weighted Dollar Days
		(a)	(b)	(c) = (a) x (b)
1	Hourly	77,293	13.0	1,004,812
2	Salaried	153,477	6.0	920,861
3	Benefits	147,660	93.1	13,744,519
4	Total	378,430	41.4	15,670,192

4.2.2 Other O&M

All remaining O&M costs that did not get analyzed in the above sections were included in the Other O&M category and looked at separately. This consisted of Bad Debts, Allocated Costs and Other.

Bad debt was assigned an expense lead of zero to exclude the resulting working capital impact from the study since this is a non-cash item.

Allocated costs are costs that are incurred outside of and allocated to Enbridge Gas. These costs include compensation, benefits and other expenses for Non-Enbridge Gas Central Function (CF) employees supporting Enbridge Gas. These also include Insurance costs incurred at EI. CF charges are accrued on a monthly basis, however, settled by Enbridge Gas with EI on a quarterly basis. Using the weighted average approach, an average of 75.9 days was calculated for the year. Table 4-4 sets out a summary of the allocated cost lead days.

For the other costs, a listing of invoices was obtained from Accounts Payable, and a random sample of invoices were selected. The sample size was 96 and was determined using a 95% confidence interval and 10% margin of error. The invoice listing was filtered to exclude any expense already reviewed separately (S&W, Benefits, Property Taxes etc.). Those remaining invoices were sampled and analyzed to calculate the lead day for each. Each was reviewed to determine its service lead (where applicable) and payment lead, added together for total lead. The average lead days of all 96 invoices was then calculated and applied. Using this approach, an average of 36.2 days was calculated for the year. Table 4-4 sets out a summary of the Other O&M expense lead days.

Table 4-4

Other O&M Lead

Line No.	Particulars ($000s)	Amount	Expense Lead (Days)	Weighted Dollar Days
		(a)	(b)	(c) = (a) x (b)
1	Bad Debt	9,400	-	-
2	Allocated Costs	153,252	75.9	11,627,999
3	Other	375,018	36.2	13,567,056
4	Total	537,670	46.9	25,195,055

4.3 Property Tax

Enbridge Gas makes property tax payments to numerous municipalities across the province of Ontario. Historically property taxes payments have not been analyzed separately as part of the lead/lag study by either Union or EGD. Enbridge Gas has determined it is appropriate to include these payments in the working cash allowance calculation as it represents a cash expense made from current revenues with distinct payment terms varying by municipality. Given the magnitude of the payments and distinct payment terms that differ from the other expenses incurred, actual property tax payment records were analyzed on their own.

Property tax payments range from one to six installments per year at varying times. The service period of property tax payments is the entire year given the ongoing nature of the service. Using the mid-point approach, this results in a service period of 182.5 days. The property tax lead days were calculated using the actual payment dates for all property tax payments. To the extent payments are made before the mid-point, the payment lead is negative (prepayment), and to the extent payments are made after the mid-point, the payment lead is positive. Using the weighted average approach, a weighted average of (17.5) days was calculated for the year. Table 4-5 sets out a summary of the Property Tax payment lead days.

Table 4-5

Property Tax Expense Lead

Line No.	Particulars ($000s)	Amount	Expense Lead (Days)	Weighted Dollar Days
		(a)	(b)	(c) = (a) x (b)
1	Property Tax Expense	116,100	(17.5)	(2,031,750)
2	Total	116,100	(17.5)	(2,031,750)

4.4 Interest Expense

Enbridge Gas makes interest payments on both long-term debt (LTD) and short-term debt (STD) throughout the year. Historically these interest payments have not been analyzed as part of the lead/lag study by either Union or EGD, however Enbridge Gas has determined it is appropriate to include this interest in the working cash allowance calculation as it represents a cash expense made from current revenues. For the purposes of this study, consistent with interest expenses used in rate regulation, only utility interest expense costs were considered. The payment leads for interest expense were analyzed using actual interest payment records for LTD and STD.

The service period of LTD is the entire calendar year given the ongoing nature of the service. Using the mid-point approach, this results in a service period of 182.5 days. Interest payments on each LTD instrument are generally made twice a year at varying times, where some payments are made before the mid-point, resulting in a negative lead (prepayment) and others occurring after the mid-point, resulting in a positive lead. Using the weighted average approach, a weighted average of 10.5 days was calculated for the year.

For STD the service periods range depending on the term of the borrowing. The mid-point approach was used to determine the service lead for each borrowing. For each service lead, the mid-point is calculated on the borrowing term. Payment lead is the time between the service end date and the payment date, which is generally the same day, and thus a lead of zero. Using the weighted average approach, a weighted average of 18.4 days was calculated for the year.

The majority of Enbridge Gas's fixed financing costs consist of standby fees paid on our STD to our banking institution on a quarterly basis. Each quarter has between 90 to 92 days, applying the mid-point approach results in a service lead ranging from 45 to 46 days. The payment lead ranged from 5 to 6 days. Using the weighted average approach, an average of 51.2 days was calculated for the year for standby fees and 61.6 days across all fixed financing costs. Table 4-6 sets out a summary of the Interest Expense lead days.

Table 4-6

Interest Expense Lead

Line No.	Particulars ($000s)	Amount	Expense Lead (Days)	Weighted Dollar Days
		(a)	(b)	(c) = (a) x (b)
1	Long-Term Debt Interest Expense	371,300	10.5	3,898,650
2	Short-Term Debt Interest Expense	1,900	18.4	34,960
3	Fixed Financing Amounts	6,800	61.6	418,880
4	Total	380,000	11.5	4,352,490

4.5 Income Tax

Enbridge Gas makes regular remittances to relevant tax authorities. In accordance with the Income Tax Act Enbridge Gas's installment payments are made monthly and are due the last day of each month. For the purposes of this study, consistent with income taxes used in rate regulation, only utility taxes were considered. Therefore, actual income tax remittances are not applicable and income taxes were looked at on a theoretical basis. A mid-point approach was used for determining the receipt date of the service. Payments were assumed to be made on the last day of the month in accordance with the statutory requirement resulting in a payment lead of zero. Using the weighted average approach, an average of 15.2 days was calculated for the year. Table 4-7 sets out a summary of Income Tax expense lead days.

Table 4-7

Income Tax Expense Lead

Line No.	Particulars ($000s)	Amount (a)	Expense Lead (Days) (b)	Weighted Dollar Days (c) = (a) x (b)
1	Income Tax Expense	43,100	15.2	655,120
2	Total	43,100	15.2	655,120

5. Sales Tax

Enbridge Gas collects and remits Harmonized Sales Tax (HST) on payments received from customers, as well as pays and recovers both Goods and Services Tax (GST) and HST on payments made to vendors.

An HST lead occurs on revenues collected by Enbridge Gas. The HST lead represents the number of days from the date the HST is collected from the customer to the date Enbridge Gas is required to remit payment which was calculated to be 24.6 days. Remittances are made monthly and are due the last day of the following month.

A GST/HST lag occurs on certain Enbridge Gas expenses. The GST/HST lag is the time between the date GST/HST is paid on taxable purchases, and the date when Enbridge Gas receives the associated input tax credit. The lag days calculated for invoice payments was 30.9 days. Given this, the mid-point approach was used resulting in a service lead of 15.2 days. With payments being made the last day of the following month the average payment lead was calculated to be 45.5. Using the weighted average approach, a net HST average of 6.3 days was calculated for the year.

Table 5

Sales Tax Lag

Line No.	Particulars ($000s)	Amount (a)	Lead/Lag (Days) (b)	Weighted Dollar Days (c) = (a) x (b)
1	HST Customer Billing Lead	(786.90)	(24.6)	(19,379.79)
2	GST/HST Invoice Payment Lag	416.89	30.9	12,896.45
3	Net Sales Tax Lag		6.3	

6. Federal Carbon

Ontario is subject to the Federal Government’s carbon pricing program (otherwise known as the Federal Carbon Pricing Backstop Program), which includes a carbon charge on fossil fuels, including natural gas. Under this program Enbridge Gas remits the federal carbon charge related to amounts billed to customers for the gas they consume.

Enbridge Gas collects the carbon charge from customers through its monthly billing process and therefore the collection of the charge follows the same collection lag as Gas Sales of 21.2 days.

Remittances are made monthly and are due on the last day of the month following a customer being billed. A mid-point approach was used resulting in a service lead period of 15.2 days and remittances were assumed to be made on the last day of the month in accordance with the statutory requirement. Using the weighted average approach, a weighted expense lead of 45.5 days.

In summary, with the collection lag of 21.2 days and the remittance lead of 45.5 results in a net lead of 24.3 days.

Natural gas consumed in the operation of applicable Enbridge Gas facilities is subject to the carbon charge and output-based pricing system. These amounts are reflected in the revenue lag and gas costs lead calculations.

Table 6

Carbon Charge Customer Portion Lead

Line No.	Particulars ($000s)	Amount	Expense Lead (Days)	Weighted Dollar Days
		(a)	(b)	(c) = (a) x (b)
1	Customer Portion Collections	(1,089,400)	21.2	(23,095,100)
2	Customer Portion Remittances	1,089,400	45.5	49,567,700
3	Total		(24.3)	

7. Findings and Conclusions

The results of this study are combined and summarized in Table 7 below and provide the lead-lag days for Enbridge Gas which are used in determining its working cash allowance for the 2024 Test Year and throughout the next IR Term.

Table 7

Summary of Lead/Lag Results

Line No.	Particulars (Days)	Revenue (Days)	Expense (Days)	Net (Days)
		(a)	(b)	(c) = (a) - (b)
1	Gas Costs	39.5	39.2	0.3
2	Operations and Maintenance	39.5	44.6	(5.1)
3	Property Tax Expense	39.5	(17.5)	57.0
4	Interest Expense	39.5	11.5	28.1
5	Income Tax Expense	39.5	15.2	24.3
6	Net Expenditure Lag			4.0
7	Sales Tax			6.3
8	Federal Carbon			(24.3)

8. Appendices

8.1 Variance analysis back to 2013 OEB-Approved

This section addresses the lead/lag days proposed for 2024 compared back to 2013 OEB-approved. See Table 8.1 below for an analysis of the current year back to OEB-approved.

Overall, the results of this study are largely the same as previous studies, with most of the days falling in between Union and EGDs board approved amounts, which is to be expected when amalgamating two companies and harmonizing the methodologies.

The largest variances relate to O&M expense lead where days increased 23.8 compared back to 2013 Union whereas the days decreased 16.3 compared back to 2013 EGD. The difference between the 2024 days and the 2013 days is largely driven by the centralization and harmonization of systems, policies, and procedures across all areas of O&M including: compensation & benefits, allocated costs and accounts payable. Another driver of the variance is due to the introduction of new items (property tax, interest expense and income taxes) which were not separated out in previous studies. The last major driver is due to the introduction of the federal carbon charge and its related lead days. The impact of this charge will have an impact on the allowance for working cash that is expected to continue to grow through the rebasing term.

Table 8.1

Lead/Lag Results Proposed vs Approved

Line No.	Particulars	Proposed 2024 EGI Lead/Lag (Days) (1)	Approved 2013 Union Lead/Lag (Days)	Approved 2013 EGD Lead/Lag (Days)
	Revenue Lags:			
1	Gas Sales & Distribution			
	General Service	39.8	39.3	42.4
	Contract	38.5	33.6	40.8
2	Storage and Transportation	35.1	33.1	N/A
3	Other Revenue	39.8	38.3	N/A
1	Overall Operating Revenue Lag	39.5	38.1	42.2
	Cost of Service Expense Leads:			
2	Gas Cost Lead	39.2	38.8	38.2
3	Overall O&M Expense Lead	44.6	20.8	60.9
4	Property Tax Expense	(17.5)	N/A	N/A
5	Interest Expense	11.5	N/A	N/A
6	Income Tax Expense	15.2	N/A	N/A
7	Storage Costs	N/A	N/A	(20.3)
8	Storage Municipal & Capital Taxes	N/A	N/A	17.8
9	Total Expenditures	35.5	20.8	58.4
10	Net HST Lag	6.3	12.9	1.8
11	Net Carbon Lag	(24.3)	N/A	N/A

Notes:

(1) Enbridge Gas Proposed 2024 based on 2021 Actuals

(2) N/A indicates newly added lead/lag categories that were not included in prior EGD and Union lead/lag studies or for a category that is no longer included in EGI's lead/lag study.

CAPITALIZATION POLICY - OVERVIEW

DANIELLE DREVENY, MANAGER CAPITAL FINANCIAL PLANNING & ANALYSIS

1. The purpose of this evidence is to provide an overview of the capitalization policy used by Enbridge Gas and the alignment actions that have been undertaken as a result of the amalgamation of EGD and Union. Enbridge Gas has adopted the Enbridge Enterprise Wide Capitalization Policy. The capitalization policy underpins Rate Base, Property Plant and Equipment and Capital Expenditures as provided at Exhibit 2, Tab 1, Schedule 1, Exhibit 2, Tab 2, Schedule 1, and Exhibit 2, Tab 5, Schedule 1, respectively. Additionally, Enbridge Gas is requesting approval to continue capitalizing indirect overheads, as previously approved by the OEB for EGD and Union. EGD and Union each had separate methodologies previously approved by the OEB, and Enbridge Gas is requesting approval for a harmonized methodology for capitalizing indirect overheads provided at Exhibit 2, Tab 4, Schedule 2.

2. This evidence also sets out Enbridge Gas's request regarding approval of the amounts contained within the Accounting Policy Change Deferral Account (APCDA) associated with the changes in capitalization policy and the change from harmonizing the calculation of Interest During Construction (IDC) for capital projects. Please see Exhibit 9, Tab 2, Schedule 1, Attachments 3-4 for the resulting revenue requirement impact recorded in the APCDA.

3. This evidence is organized as follows:
    1. Capitalization Policies Prior to Amalgamation
    2. Enbridge Enterprise Wide Capitalization Policy
    3. Accounting Treatment Harmonization at Amalgamation

4. Impacts of Alignment/Harmonization and APCDA Considerations

<u>1. Capitalization Policies Prior to Amalgamation</u>

4. EGD and Union operated under their respective capitalization policies from 2013 through to the merger of Enbridge Inc. and Spectra Energy Corp. There were no significant changes to either of the capitalization policies from 2013 to the middle of 2018.

5. The previous EGD and Union capitalization policies were developed pursuant to US GAAP and applicable provisions of the OEB's Uniform System of Accounts (USOA) for Class "A" Gas Utilities. The respective policies applied the provisions of US GAAP Accounting Standards Codification (ASC) 360 – Property, Plant, and Equipment (ASC 360). In addition, EGD and Union both considered guidance from US GAAP ASC 980 – Regulated Operations in determining capital treatment of costs. ASC 980 allows a regulated utility to treat certain costs in a manner that differs from the provisions of ASC 360 if approved by the regulator for rate making.

6. The capitalization policies set forth criteria to determine when costs should be capitalized to Property, Plant and Equipment (PP&E) or expensed. Capital costs include all costs to bring an asset to the location and condition necessary for its intended use. ASC 360-10-05-03 defines PP&E as consisting of long-lived assets used to create and distribute the entity's products and services. This includes costs related to:
   a) Land and land improvements;
   b) Buildings;
   c) Machinery and Equipment; and
   d) Furniture and Equipment.

2. Enbridge Enterprise Wide Capitalization Policy

7. Subsequent to the merger, Enbridge and its business units, including Enbridge Gas, revisited its Enbridge Enterprise Wide Capitalization Policy in order to consolidate, harmonize and supersede all previous capitalization policies, inclusive of previous Spectra entities including Union. This policy was implemented in August 2018. The purpose was to ensure all business units operated under one harmonized capitalization policy that provided guidance on consistent treatment in accordance with US GAAP. As a result of the implementation, there were no material revenue requirement impacts identified in 2018 or thereafter. The Enbridge Enterprise Wide Capitalization Policy is provided at Attachment 1.

3. Accounting Treatment Harmonization at Amalgamation

8. The amalgamation of EGD and Union required Enbridge Gas to review all existing accounting polices to identify where alignment was required. Although prior to the amalgamation both EGD and Union followed US GAAP and Enbridge policies such as the Enterprise Wide Capitalization Policy, the two utilities treated various transactions and costs differently, which required harmonization upon amalgamation. Sections 3.1.to 3.3 outline the 3 areas of harmonization for Enbridge Gas.

3.1. O&M vs Capital Treatment of Specific Transactions/Programs

9. Upon review, management identified differences in the historical capitalization treatment for costs related to certain operations, maintenance, and research and development programs. The differences were a result how EGD and Union interpreted and applied US GAAP to specific costs. The programs and costs listed below were expensed as incurred by Union whereas EGD capitalized and depreciated these costs. These treatments were accepted for rate making purposes

through inclusion in each of the utility's approved forecast capital plan underpinning rates.[1]

10. For alignment and harmonization purposes, Enbridge Gas revisited the prior interpretations and adopted the guidance of ASC 360 in determining the treatment of the below noted costs. In these instances ASC 360 would require these costs to be expensed as incurred, where ASC 980 would allow for these costs to be capitalized if approved by a regulator. Therefore, Enbridge Gas has included these costs in its 2024 forecast O&M costs, rather than its 2024 forecast capital plan.

Verification of Maximum Operating Pressure Program (MOP)

11. The cost associated with this program primarily related to the quality assurance verification of the maximum operating pressure of Enbridge Gas's highest-pressure pipelines.[2] The program consisted of field investigations, creating and maintaining a database for relevant records associated with each pipeline, and completing engineering assessments to ensure compliance with code. Prior to amalgamation, EGD capitalized the costs whereas Union expensed the costs. (Maximum operating pressure) MOP verification costs have been expensed by Enbridge Gas effective January 1, 2019, and through the end of 2019. The MOP program concluded at the end of 2019.

Distribution Integrity Technology

12. These are costs associated with funding of third-party research and development work in the areas of distribution system integrity management, damage prevention, leak and corrosion management, and safety. By supporting these new

[1] EGD EB-2012-0459 and Union EB-2011-0210.
[2] In total these pipelines are approximately 3,500km in length.

technologies, EGD received sample prototypes, such as a piece of leak detection equipment. If the prototype was proven successful, the third-party company would take the prototype to production and EGD would then have the option of purchasing the equipment for its own use. However, these purchases were separate from the annual administrative fee, which did not include equipment purchase. Prior to amalgamation, EGD capitalized these costs. Union did not have similar types of costs. The Distribution Integrity Technology costs have been expensed by Enbridge Gas effective January 1, 2019, and going forward.

Distribution Records Management Program

13. These are costs related to the enhancement of the records management practices including various programs aimed to update, digitize and manage existing records across the Pipe, Stations, and Storage Asset Classes to ensure they meet compliance and internal standards. Prior to amalgamation, EGD capitalized these costs whereas Union expensed them. The Distribution Records Management program costs have been expensed by Enbridge Gas effective January 1, 2019, and going forward.

Integrity Digs

14. These costs are related to the Integrity Dig Program which is a component of the Enbridge Gas Integrity Management Program. The purpose of the Integrity program is to ensure the safe and reliable operation of pipeline assets. Inline Inspections (ILI) are conducted to monitor for potential anomalies in the pipe and as a result, subsequent digs may be required to remediate and repair the pipeline. Prior to amalgamation, EGD capitalized these costs whereas Union expensed digs that did not result in the replacement of at least 1 metre of pipe. Enbridge Gas adopted the Enterprise Wide Capitalization Policy and capitalizes integrity digs resulting from

defects detected by an ILI and resulting remediation efforts including repair such as sleeving and recoating or leak repair. Any digs that are investigative in nature, such as External Corrosion Direct Assessment (ECDA) are not eligible for capitalization. Additionally, any sleeving and recoating performed outside of a proactive rehabilitation program, such as for leak repair, will be expensed. Integrity Digs as a result of ILI have been capitalized by Enbridge Gas effective January 1, 2019 and going forward.

3.2. Treatment/Calculation of Interest During Construction

Background and Accounting Guidance

15. The OEB issued an approach for setting interest rates in 2006[3] with the view that rate regulated utilities in the energy sector should be consistent in the use of interest rate methodologies. With respect to implementation of the guidance, a utility could continue to use a specific rate previously approved by the OEB in a proceeding. However, the OEB could direct the utility in a subsequent proceeding to adopt the interest rate as prescribed under its accounting interest rates policy.

16. Interest expense incurred for borrowed funds is capitalized to a project in accordance with ASC 835-20 - Interest, Capitalization of Interest.
The Capitalization period begins when all three of the following conditions are present:
    a) Interest cost is incurred;
    b) Construction activities are in progress; and
    c) Expenditures are incurred.

[3] EB-2006-0117, Approval of Accounting Interest Rates Methodology for Regulatory Accounts, November 28, 2006.

The capitalization period ends when:

a) The asset is substantially complete; and
b) The asset is ready for its intended use.

Harmonization of IDC Treatment

17. Prior to amalgamation, EGD capitalized interest on all capital projects involving the construction of an asset. The rate used for capitalization purposes was the Weighted Average Cost of Debt (WACD). The WACD rate was calculated by EGD annually based on the capital structure using the weighted average of all short-term and long-term debt. EGD submitted its 2007 Rates Application[4] prior to the issuance of the OEB's accounting interest rate policy. The capital budget in that proceeding was settled including the cost of IDC at a WACD rate. In EGD's 2014 to 2018 IRM Application[5], the OEB did not direct EGD to adopt the prescribed interest rate and the IRM Application was approved using the WACD rate. In contrast, Union capitalized interest only on capital projects involving the construction of an asset that exceeded the spend and duration requirements of $1 million and 12 months. The rate used for capitalization purposes was the OEB's prescribed interest rate for Construction Work In Progress (CWIP). Union filed its 2013 Cost of Service Application[6] stating the use of the OEB's prescribed interest rate for regulated assets to calculate IDC. The topic was not specifically discussed in the Decision and Order, however it was inherently approved through the approval of the Application.

18. Enbridge Gas has adopted the OEB's accounting interest rate policy effective January 1, 2019, and going forward. Additionally, Enbridge Gas has adopted the

[4] EB-2006-0034.
[5] EB 2012-0459.
[6] EB-2011-0210.

approach of capitalizing interest for all capital projects that involve the construction of a capital asset effective January 1, 2019, and going forward in accordance with US GAAP.

3.3. Overhead Capitalization

19. The capitalization of indirect overheads is permissible for a regulated utility under the provisions of ASC 980. Prior to amalgamation, both EGD and Union had separate overhead capitalization policies which were approved by the OEB. A new harmonized overhead capitalization policy was implemented as of January 1, 2020, to align and harmonize the previous methodologies of EGD and Union. Please see Exhibit 2, Tab 4, Schedule 2 for a discussion on the policy change and the resulting impacts to O&M and Capital expenses.

4. Impacts of Alignment/Harmonization and APCDA Considerations

20. A deferral account was established as an outcome of the MAADs Decision[7] to record the impact of any accounting changes required as a result of the amalgamation that affect revenue requirement. Each of the capitalization alignment changes noted in Section 3 result in changes that impact the annual revenue requirement. The changes were implemented in 2019 on a prospective basis and the associated revenue requirement impacts of each alignment activity has been tracked since 2019 and recorded in the APCDA on a cumulative basis in accordance with the directive resulting from the MAADs Decision and parameters of the APCDA as approved by the OEB. Please see Exhibit 9, Tab 2, Schedule 1 for further details of these impacts recorded in the APCDA and proposed disposal thereof.

[7] EB-2017-0306/EB-2017-0307, OEB Decision and Order, August 30, 2018.

21. Table 1 outlines the impact (increase or decrease) to annual capital costs with an offsetting impact to O&M where applicable for 2019 to 2021 actuals and the forecasted impacts for the 2022 Estimate, 2023 Bridge Year and 2024 Test Year. The associated revenue requirement impact and corresponding APCDA entry is provided at Exhibit 9, Tab 2, Schedule 1, Attachments 2-3.

Table 1

APCDA Capitalization Policy Impacts - Capital Expenditures

Line No.	Particulars ($000s)	Utility	2019 Actual	2020 Actual	2021 Actual	2022 Estimate	2023 Bridge Year	2024 Test Year
			(b)	(c)	(d)	(e)	(f)	(g)
1	MOP Verification	EGI	(0.7)	0.0	0.0	0.0	0.0	0.0
2	Distribution Integrity Technology	EGI	(1.3)	(0.2)	0.0	0.0	(0.6)	(0.6)
3	Distribution Records Management Program	EGI	(3.8)	(1.0)	(0.9)	(1.4)	(0.4)	(0.5)
4	Integrity Digs	EGI	1.4	5.9	4.6	3.6	7.1	6.1
5	Sub-Total O&M Impacts		(4.4)	4.8	3.6	2.2	6.1	5.0
6	Interest During Construction	EGI	1.0	0.3	0.8	0.0	(0.8)	(1.0)

Note:

(1) Negatives represent decreases in capitalization and increases to O&M for lines 1 to 5.

(2) Positives represent an increase in capitalization and a decrease in interest expense for line 6.

Enterprise Wide Capitalization Policy

Policy management:	
	Title
Policy Preparer	Director Capital Assets
Policy Owner	Director Capital Assets
Policy Approver	Chief Accounting Officer

Policy version control:		
Version	**Approval Date**	**Effective Date**
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1. Executive summary

Enbridge Inc. is subject to U.S. Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") which sets out generally accepted accounting principles for entities that utilize United States Generally Accepted Accounting Principles ("US GAAP").

The principles outlined within this Enterprise Wide Capitalization Policy ("Policy") establish guidelines and procedures for the Capitalization of Property, Plant and Equipment ("PP&E"), internally developed and externally acquired information technology hardware, software, and eligible project Costs.

Non-compliance with this Policy constitutes a violation of the Enbridge Statement on Business Conduct and may result in disciplinary action up to and including termination.

2. Purpose

The purpose of this Policy is to provide management with the framework and principles within which to account for the Capitalization of PP&E, internally developed and externally acquired information technology hardware, software, and eligible project Costs.

3. Definitions

Asset – An expenditure incurred that results in "…probable future economic benefits obtained or controlled by a particular entity as a result of past transactions or events."

Authorities and Spending Limits (ASLs) – Delegated authority to officers and certain other individuals to approve ASL Transactions on behalf of the Company (including on behalf of its Applicable Subsidiaries and Applicable Joint Ventures) to Enbridge employees (and approved contractors) at specified salary grade levels. (see the Authorities and Spending Limits Policy)

Authorization for Expenditure (AFE) – Spending for a Capital Project that has been approved (a) by the Board or (b) by management with the appropriate ASLs, which can be committed to a third party.

Base Pressure Gas – The volume of gas in underground storage which is required as a base pressure for the operation of underground storage areas'

Board – Enbridge Inc. Board of Directors.

Capitalization – The costs to acquire an asset are expensed over the life of that Asset rather than in the period the expense was incurred.

Carrying Amount – The amount of an item as displayed in the financial statements. In the case of PP&E, it is the net book value (i.e., gross Cost less accumulated Depreciation).

Company – Enbridge Inc. and its Subsidiaries.

Cost – The amount of cash or cash equivalents paid or the fair value of the other consideration given to acquire an Asset at the time of its acquisition or construction.

Depreciation – The systematic and rational allocation of the Depreciable Amount of an Asset over its estimated Useful Life.

Depreciable Amount – The gross Cost of the Asset reduced by its estimated salvage value.

Directly Attributable Costs – Incremental Costs incurred by the Company that are linked to its capital program such that if the capital program ceased, those Costs would not be incurred.

Fair Value – The price that would be received to sell an Asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date.

Group Method of Depreciation – A method of Depreciation where similar Assets with comparable useful lives are grouped and depreciated as a pool. When those Assets are retired or otherwise disposed of, gains and losses are not reflected in earnings, but are booked as an adjustment to accumulated Depreciation.

In-Service Date – The date on which a project is considered to be complete and ready to begin operating as intended.

Linefill – The amount of gas, oil or product required to fill a new line before deliveries can be made at take-off points or the end of the line.

Linepack – The volume of gas or oil maintained in a pipeline at all times in order to maintain pressure and provide uninterrupted flow of gas or oil.

Material – The omission or misstatement of an item in a financial report is Material if, in the light of surrounding circumstances, the magnitude of the item is such that it is Probable that the judgment of a reasonable person relying upon the report would have been changed or influenced by the inclusion or correction of the item.

Probable – Likely to occur, which is generally interpreted to have a greater than 75% likelihood of occurring.

Residual Value – The estimated fair value of an Asset at the end of its Useful Life to the entity, less any disposal Costs.

Subsidiary – With respect to Enbridge Inc., any corporation, partnership (general or limited, including master limited), limited liability company, trust, joint venture, joint stock company, unincorporated association, unincorporated syndicate, unincorporated organization, or other entity or association that is directly or indirectly controlled by Enbridge Inc.

Unit of Property – A complete structure, apparatus or item of equipment that constitutes a part of any installation or property and includes a part of any structure or apparatus where such part is a physically distinct part of the structure and the value of such part is Material. Units of property are documented by the business units**.** A minor Unit of Property is defined as an associated part or item included within a larger Unit of Property.

Useful Life – The period over which an Asset is expected to contribute directly or indirectly to generating future cash flows.

Utilities – Rate Regulated natural gas Utilities.

4. General

This Policy sets out the general principles to be followed in determining the types of expenditures which may be capitalized for the Company, excluding those situations as described in *Section 4.1 – Scope exclusions*.

This Policy is to be read in conjunction with the following policies:

- **Enterprise Wide Revenue Recognition Policy** – provides guidance for the determination of the accounting treatment of revenue.

- **Authorities & Spending Limits Policy** – provides guidance on the management of capital commitments, expenditure budgets and related operating plans by delegating approval to the appropriate level within the company

This Policy supersedes all existing Policies and procedures related to Capitalization in effect at all locations except when specifically referred.

This Policy is not meant to replace the applicable US GAAP, but instead outlines the situations that are most applicable to the Company.

4.1 Scope exclusions

The following are excluded from the scope of this Policy:

- Agreements or filings that are in effect with regulatory bodies;
- Some projects attract Capitalized Costs in accordance with ASC 980 Regulated Operations. For operations that are subject to rate regulation, all or part of an incurred Cost that would otherwise be charged to expense under this Policy may be Capitalized if the scope and criteria for Capitalization pursuant to ASC 980 are met for that entity, including these costs in the project are not subject to additional approval
- Depreciation and amortization of capital Assets;
- Identified Assets within the scope of ASC 840 or ASC 842;
- Impairment or disposal of long-lived Assets; and
- Property acquired as part of a business combination.

4.2 Governance

The Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") are responsible for ensuring that the Company's financial condition and results of operations are fairly presented in the financial statements and for establishing and maintaining the Company's disclosure controls and procedures and internal controls over financial reporting. The CEO and CFO have delegated to the Chief Accounting Officer ("CAO") responsibility for accounting and internal controls, which includes the sub-delegation of activities to support the fair presentation of the financial statements and assessment of effectiveness of internal controls. Capitalization of expenditures is a critical component of the accounting activities.

4.3 Project Classifications

The Capital Asset group is responsible for maintaining the definitions and providing governance over the capital project classification process. For example, maintenance and growth categories.

5. PP&E recognition - When does Capitalization commence?

5.1 Projects requiring individual approval under the applicable ASLs

For those projects that require individual ASL approval and which are funded separately from the approved capital budget, all internal and external Costs incurred are to be expensed until the project has progressed to the stage at which the criteria for Capitalization set out below have been met. For purposes of this Policy, project expenditures may be Capitalized when all the following criteria, supported by internal and external documentary evidence, which may include approved minutes of Board meetings and AFEs, have been satisfied and the project is Probable of being constructed:

- Evidence which demonstrates the existence of a market for the output(s) of the project;
- The project has been approved under the applicable ASLs;
- Significant legal, regulatory, and operational requirements related to the project have been met or are reasonably expected to be met; and
- Adequate technical, financial and other resources necessary in order to complete the project are available or have been obtained.

Prior to meeting the criteria set out above, no Costs may be Capitalized. For projects that are approved by the Board during a quarterly meeting, judgment would be applied to determine at what point during the preceding quarter it was Probable that the project would proceed. Project expenditures may be Capitalized from this point forward. It is important to note that project Costs previously written off as period expenses in prior externally reported periods would not be subsequently reinstated because the status of the project at the time the Costs were incurred was too uncertain to establish a relationship with future benefits, and accordingly, the Costs were properly charged to expense in those periods. Any subsequent recovery of external third-party Costs previously expensed would be included in earnings as a reduction of period Costs (e.g. the recovery of project Costs from a shipper as part of the terms of a Memorandum of Understanding ("MOU") or other form of written agreement).

The following diagram depicts the life cycle of a typical capital project and when Costs are Capitalized vs. expensed in relation to the project stage:

Pre-operating period		Operating period
Pre-approval stage	After approval "activities"	Asset in service
	Example of activities: Pre-construction - technical drawings and specifications, process of obtaining required permits from governmental authorities, etc. Construction activities - physical construction of the Asset and all steps required in order to prepare the Asset for its intended use. Unforeseen obstacles during this stage such as technical problems, labor disputes or litigation, etc. that is directly attributable to the completion of the capital project.	
Expense	Capitalize	Expense (or Capitalize if Costs fall under Trailing Costs (*Section 11.1 – Trailing Costs*) definition)

Approval date achieved if all met:

Evidence of a market for outputs, such as a MOU or other agreement with a customer, is in place or is being developed.

The project has been approved under the applicable ASLs.

Significant legal, regulatory and operational requirements related to the project have been met or are reasonably expected to be met. Adequate technical, financial and other resources necessary in order to complete the project are available or have been obtained.

In service date:

Asset is in the location and condition necessary for it to operate in the manner intended.

5.2 Projects funded through the annual capital budget

Pipeline integrity, core maintenance and major overhauls are recurring items. Projects for these activities are included in the annual capital budget process and receive funding approval when the Board approves the capital budget. These budgets are often referred to as Program Funding Portfolios.

The funding within the portfolios can be substituted between various projects without the requirement to receive additional Board approval as the overall funding was approved during the budget process. These projects are evaluated and approved according to guidance outlined in the Authority & Spending Limits Policy (ASL)

Expenditures on these projects may be Capitalized immediately and are subject to the criteria in this Policy. Projects, those submitted into the annual capital budget, as well as any subsequent substitutions must be evaluated for Capitalization as they are raised as a capital project through the Capital Assets group.

6. PP&E recognition - capital vs. expense overview

It is important to determine which Costs may or may not be Capitalized to produce accurate financial statements. Capital Assets are shown on the balance sheet. Costs which may not be Capitalized are expensed in the period in which they are incurred. Accordingly, an expenditure that is incurred in one period, but which is anticipated to result in economic benefits over a number of years in the future and which meets the definition of an Asset is Capitalized. The Cost of Asset used in the earnings process is recognized through an annual Depreciation charge.

ASC 360-10-05-3 states that PP&E typically consist of tangible long-lived Assets used to create and distribute an entity's products and services and typically includes land and land improvements, buildings, machinery and equipment, and furniture and fixtures.

ASC 360-10-30-1 states that the historic Cost of acquiring or constructing an Asset includes all Costs necessary to bring the Asset to the location and condition necessary for its intended use. There is no formal accounting guidance on how to determine if the Asset is ready for its intended use. It is a point in time at which management decides that all significant testing and commissioning for the Asset has been completed and the project is deemed available for operation. If an Asset requires a period of time in which to carry out the activities necessary to bring it to that location and condition, the interest Cost ("AIDC") incurred during that period as a result of expenditures made to construct the Asset is included in the Cost of the Asset (as per ASC 835-20-05-1).

US GAAP does not provide specific guidance regarding the nature of expenditures which can be Capitalized as part of PP&E. As a result, the decision as to whether a particular expenditure may be Capitalized is determined to a considerable extent by the definition of an Asset set out in FASB Statement of Financial Accounting Concepts 6, wherein Assets are defined as "…probable future economic benefits obtained or controlled by a particular entity as a result of past transactions or events." Accordingly, if an expenditure is expected to result in a Probable future economic benefit to the Company, it is eligible for Capitalization. For a sample listing of activities and expenditures that are allowed or disallowed for Capitalization, please refer to *Appendix 2 – Directly Attributable capital Cost inclusions* and *Appendix 3 – Directly Attributable capital Cost exclusions* for additional guidance.

Decision trees for Capitalization and expense related to the 2 areas below can be found in *Appendix 4 – Decision tree for Capitalization* and *Appendix 5 – Decision tree for improvements and replacements*.

6.1 Projects funded through the annual capital budget

Expenditures for individual items of PP&E with a Cost greater than or equal to $10,000 are eligible for Capitalization, except for the Regulated Utilities where the threshold is minimum $1,000. The Capitalization threshold applies to an Asset at a single physical location. Splitting or aggregating Asset expenditures for multiple purchases at a single location or an Asset at multiple locations to circumvent the Capitalization threshold is not allowed.

In certain cases, a number of Assets which individually Cost less than the threshold are purchased together at one location, or pooled, for Capitalization.
Examples Include:

- Computer equipment/peripherals and software
- Office furniture and equipment
- Telephones, Communication Equipment
- Meters and Regulators (specifically those used in the Gas Distribution business units)

In such cases, the entire Cost of the purchase is Capitalized as a single or grouped Asset.

The Company's rate regulatory operations may require special considerations for limits, agreements or guidelines set with regulatory bodies. Therefore, any thresholds established with the regulatory body will supersede the limit noted above.

7. Project construction including new builds, additions and extensions

If a project is eligible for Capitalization based on the assessment carried out in *Section 5 – PP&E recognition – When does Capitalization commence?* all expenditures coded to a capital project or group of capital projects must meet the criteria for Capitalization. Any expenditure incurred which is Directly Attributable and necessary to bring the Asset to the location and condition for its intended use may be Capitalized under ASC 835-20-05-1.

7.1 Directly Attributable Cost inclusions

For the Company, Directly Attributable Costs are defined as expenditures incurred by the Company that are directly related to a particular capital program or project such that if that project had not been undertaken, those Costs would not have been incurred. For clarity and to ensure consistency in the Capitalization of Costs, please refer to *Appendix 2 – Directly Attributable capital Cost inclusions* for a sample listing of examples.

Regulated Company entities are to also refer to applicable guidelines established by the regulator when determining if items should be treated as capital or expense.

7.2 Directly Attributable Cost exclusions

Directly Attributable Cost exclusions are Costs incurred that are to be considered expense items. For clarity and to ensure consistency in the Capitalization of Costs, please refer to *Appendix 3 – Directly Attributable capital Cost exclusions* for a sample listing of examples.

Regulated Company entities are to also refer to applicable guidelines established by the regulator when determining if item should be treated as capital or expense.

7.3 Transaction Costs for Asset acquisitions

Costs incurred to facilitate transactions accounted for as Asset acquisitions are Capitalized in accordance with ASC 805-50-30-1. However, transaction Costs incurred to acquire Assets through a business combination are expensed as incurred.

7.4 Projects group

The Projects group is a centralized group which oversees construction of large capital projects, as well as certain operating projects, and includes functions such as project management, development engineering, construction engineering and transition to operations.

The Costs incurred by the Projects group are Capitalized as they are incremental and are necessary to support construction of the projects undertaken by the Company. Those Costs form part of the expenditures that are necessary to bring the projects to the stage where they are ready for their intended use, thereby generating future economic benefits. The Company would be billed for charges of a similar nature if it outsourced the management of its projects to third-party Engineering, Procurement and Construction contractors, and those charges would similarly be Capitalized as part of the Costs of the projects.

Costs incurred within the Projects group are Capitalized, with certain exceptions such as training, memberships, Depreciation, and business process re-engineering Costs.

A portion of the Costs incurred by the Projects group is Capitalized directly to projects through allocations. Examples of Costs to be allocated include monitoring of project activity, developing engineering and safety standards, engineering design, procurement, establishing process controls, identifying resource requirements, and providing finance and administrative support.

The Projects group is allocated Costs from other Company business units when Projects utilizes their resources to complete large capital projects. Costs include burdened labor charges, IT, human resources (excluding recruiting Costs) and legal support. These Cost allocations are Capitalized except for Costs specifically excluded in *Appendix 3 – Directly Attributable capital Cost exclusions*.

To the extent the Projects group oversees and supports the execution of operating projects, these costs must be separated and expensed as incurred.

7.5 Overhead-related Costs

Certain overhead Costs are allowable for Capitalization. Please refer to the *Overhead Capitalization Memorandum* for additional guidance.

7.6 Spare parts and surplus parts and equipment

Spare parts are individual parts of a larger Asset such as a pipeline system or a wind farm which require periodic replacement over the life of the Asset. They can be broken down into four separate categories - commissioning, operational, capital and salvaged spares.

Type of Spare	Treatment	Reason
Commissioning Spares	Capital	Commissioning spares are used for replacement of damaged or faulty equipment to ensure there is no delay in the starting schedule of the new facility.
Operational Spares	Expense	Operational spares are units of equipment that are deemed essential to the operation of the Asset. Determination of which equipment meets these criteria is made through Operations' periodic review.
Capital Spares	Capital	Capital spares are items of equipment which are not being utilized in current operations but are purchased and kept on hand for emergency use as the equipment is specialized and critical to the operations of a particular item of PP&E. These capital spares would normally qualify for Capitalization if purchased new or replaced. Capital spares may be Capitalized if they are specifically related and integral to a particular item of PP&E.
Salvaged Spares	Expense	Salvaged spares are previously used spares that were part of operating (or operable) plant. When equipment of this type is

		removed from service, it is to be expensed, or if Group Method of Depreciation is applied, recorded to accumulated Depreciation. Should the salvaged spare be subsequently reused, the spare will be put into service at zero net book value.

Surplus parts and equipment are those that remain uninstalled after the completion of a project but have potential for future use on other projects. The accounting treatment of surplus parts and equipment is dependent on whether the item is operating or capital in nature. Surplus parts and equipment categorized as commissioning or capital spares are Capitalized if they are of future utility, while operational spares are charged to expense as discussed above. Any transfers of parts and equipment are accounted for at the carrying value.

7.7 Allowance for Funds Used During Construction (AFUDC) and Capitalized Interest

Allowance for Funds Used during Construction (“AFUDC”) represents the estimated Costs of financing construction projects. AFUDC consists of two components, an equity component and an interest component (AIDC). The equity component is a non-cash item that may be Capitalized under rate regulated accounting when permitted by the regulator.

i. AIDC

ASC 835-20 permits the Capitalization of actual interest expense incurred for borrowed funds. The Capitalization period begins when all three of the following conditions are present:

- Expenditures for the Asset have been made
- Activities that are necessary to get the Asset ready for its intended use are in progress; and
- Interest Cost is being incurred.

Interest Capitalization continues for as long as these conditions are present. Interest Capitalization ceases if the Company suspends substantially all activities related to the acquisition or construction of the Asset until such activities are resumed. However, brief interruptions in construction activities, interruptions that are externally imposed, and delays that are inherent in the Asset acquisition or construction process do not require cessation of interest Capitalization.

7.8 Asset Retirement Obligations (“ARO”)

An ARO is only provided for those Assets for which a legal obligation related to Asset retirement exists and for which a settlement date or range of settlement dates for the liability can be determined with sufficient accuracy to permit a reasonable estimate of the fair value of the liability to be made.

All legal obligations associated with the retirement of a tangible long-lived Asset must be identified. Legal obligations can result from:

- a government action, such as common law or statute;
- an agreement between entities, such as a written or oral contract; or
- A promise conveyed to a third party that imposes a reasonable expectation of performance.

7.9 Accounting for the receipt of damages

Damages are intended to compensate the impacted party to a contract for the failure of the other party to the contract to perform as promised. If, prior to the closure of the Authorization for Expenditures for a project, cash is received as penalties/compensation due to missed milestones or projects not completed, they do not represent revenue and are to be accounted for as a reduction of the capital Cost of the project as no activities were performed to earn revenue. If the damages are reimbursements for direct/incremental Costs not previously Capitalized, the cash received is recorded as a reduction of expenses on the income statement.

However, if damages are received subsequent to the project In-Service Date from a triggering event that is not related to the construction or installation of a project, such as the operational performance of equipment falling below the level guaranteed by the supplier, the damages are to be recorded as other revenue.

7.10 Accounting for pre-completion revenue

In some cases, incidental revenue may be generated prior to the project In-Service Date of a project. For example, electricity revenue may be generated during the testing phase of a wind or solar power project. In such cases, the incidental revenue is to be credited against the capital Cost of the project as supported by ASC 970-340-25-12.

7.11 Accounting for the sale of assets and surplus materials during construction

Temporary assets that are acquired in order to facilitate construction, plus any surplus materials that are left over may be sold at a value greater or less than the carrying value of the item. Sales proceeds can be credited to the capital project during the construction phase. However, if the sale or disposal occurs after the project is operational, significant judgement is required to determine the appropriate accounting for the proceeds. The amount of time that has passed from when the project was operational is a consideration, and in some instances gain or loss accounting may be required.

8. PP&E recognition – Improvements or replacements of existing Assets

Expenditures which are expected to result in an extension of the Useful Life or an increase in the efficiency or functionality of an Asset are Capitalized. These kinds of expenditures are broadly categorized as improvements and replacements. Improvements are Capitalized since it results in future benefit. However, all repairs and some replacement projects that do not extend the Useful Life or increase the expected output of property, plant and equipment are expensed as incurred.

Replacements are substitutions of a major part or Unit of Property with a new major part or Unit of Property. Generally, the Carrying Amount of items replaced is retired and charged to gain/loss on disposition and the Cost of the replacement is Capitalized in the proper capital Asset account.

8.1 Major overhauls and inspections

A major overhaul is an improvement of an item of PP&E when it is expected to extend the Useful Life. These programs include scheduled major overhauls for tanks, compressors and pumps. Historically, the Company has maintained the interpretation of US GAAP that the overhaul and inspection Costs tied to these major overhaul programs are considered capital Costs.

US GAAP provides guidance in regard to major overhaul and maintenance in Section ASC 908. PwC accounting and financial reporting guides point to guidance provided by AICPA Audit and Accounting Guide for Airlines (the Airline Guide) that provides a detailed interpretation of ASC 908 that can be used as a principal source of guidance on accounting for major maintenance activities in all industries.

The term “overhaul” is frequently used to describe the process of inspecting and maintaining an Asset. Overhaul Costs typically include replacement of parts and major repairs and maintenance. The accounting for the replacement of parts or components is discussed in Section 1.2.1.4 of the PwC accounting and financial reporting guides on property, plant, and equipment. The treatment of major repairs and maintenance Costs will depend on whether such Costs meet the specified criteria for recognition as an Asset. The Costs of “day-to-day servicing” of an Asset do not meet the FASB Concepts Statement No. 6, Elements of Financial Statements, Asset recognition criteria and do not qualify as major maintenance. However, major repair and maintenance programs carried out as part of a periodic inspection and overhaul and that result in future economic benefits beyond those initially expected may qualify for recognition as an Asset. The dry-docking of a ship would be an example of such an event.

There are three acceptable methods of accounting for major maintenance, as highlighted in the following table. The interpretation of ASC 908 provided by the airline guidance has consulted with the SEC on the interpretation of ASC 908 and the SEC has indicated that the guidance is to be applied by analogy to all major maintenance activities

Method	Guidance
Direct expense (ASC 908-360-25-2(a))	Overhauls associated with large fleets are relatively constant from period to period, thus most carriers recognize the Cost of overhauls as expense as they are incurred.
Deferral (ASC 908-360-30-3 and 35-6)	The actual Cost of each overhaul is Capitalized and amortized to the next overhaul.
Built-in overhaul (ASC 908-360-30-2 and 35-5)	When overhaul Costs are included or combined with other Costs, an entity would segregate Costs into components that (1) are depreciated over the Useful Life of the Asset and (2) require overhaul at periodic intervals. The Cost of the initial overhaul is Capitalized and amortized to the next overhaul, at which time the process is repeated.

Grant Thornton provides additional interpretation indicating that Major inspections and overhauls are Capitalized and amortized to the next major inspection or overhaul (built-in overhaul and deferral methods) (ASC 908-720-25-3; ASC 908-360-35-4 through 35-6).

Historically the Company's Capitalized major overhaul and API 653 Tank Program Costs. Based on US GAAP Section ASC 908-360-35-6 and the PWC accounting guidance interpretation, overhaul and inspection Costs can be Capitalized. As we have identified above, "major repair and maintenance programs carried out as part of a periodic inspection and overhaul and that result in future economic benefits beyond those initially expected may qualify for recognition as an Asset.", Therefore, inspection Costs in related to the major overhaul programs within the Company are eligible for Capitalization. However, the Costs for major overhauls must be tracked separately from the Asset on which the major overhaul is performed. All Costs from a major overhaul must be fully amortized or written off prior to the Capitalization of the next major inspection and overhaul.

8.2 Major pipeline rehabilitation projects

A major pipeline rehabilitation project involves the refurbishment of pipeline Assets, which may include sleeving, grinding, and recoating or replacement of worn, damaged or corroded pipe. These activities, as part of the major pipeline rehabilitation project, mitigate or prevent environmental contamination that has yet to occur and that otherwise may result from future operations or activities. In addition, these activities extend the Useful Life of the pipeline. Activities which may be Capitalized as part of the Cost of a major pipeline rehabilitation program include the Cost to open the ditch, clean, treat, inhibit, and recoat; rewrapping; sleeving; pipe replacements that constitute units of property (i.e. greater than 1 meter - unless governing regulatory authorities require another measure,); right of way access rights; backfill and restoration.

Pipe relocation and replacements that constitute units of property are treated as capital replacements as mentioned above in *Section 8 – PP&E Recognition – Improvements or replacements of existing Assets*.

Rate regulated operations may qualify for special considerations set with regulatory bodies. Therefore, any thresholds (i.e. pipe length restrictions) established with regulator will supersede the limit noted above.

Integrity digs are required under a pipeline rehabilitation program. The digs are necessary to gain access to areas on the pipeline which have been known to contain potential anomalies and facilitate the work that is required to extend the Useful Life of the pipeline. Accordingly, the Cost of the integrity dig is capitalized as part of the overall rehabilitation program.

However, any validation digs that are performed after the pipeline is in service and is not included in the commissioning of the pipeline does not qualify for Capitalization and must be expensed.

See *Appendix 6 – Pipeline maintenance and repair guideline* for a summary on Capitalization and expensing of Major Rehabilitation Projects.

9. PP&E recognition – Other

9.1 Contributions in Aid of Construction ("CIAC")

CIAC are reimbursements received from a third party that are generally intended to defray all or a portion of the construction Cost of new Assets or Cost to relocate, abandon or extend the life of existing Assets. For accounting purposes, the treatment of these reimbursements will depend on:

1) The relationship between the Company and the third-party payer: Is the third party an existing customer on the Company's system for which they are providing reimbursement?
2) Ownership of the CIAC related Assets following construction: Will ownership remain with the Company, will ownership be transferred to the third party or will there be joint ownership?

Scenarios that will result in deferring accounting treatment:

a) If a CIAC is received from the government where no customer relationship exists, and Asset ownership is retained by the Company, the CIAC reimbursement will be recorded as a reduction to project Costs.

   For CIAC's which are the result of regulatory actions, the payments merely serve as a Cost recovery mechanism. As the terms of the payment are stipulated by the regulator, and only allow for reimbursement of Costs incurred, these transactions are nonnegotiable in nature. Accordingly, CIAC's in regulated entity transactions are not within the scope of ASC 606, because these transactions are not negotiable, indicating that the construction activities do not constitute an entity's ongoing major and central operations and represent Cost reimbursements only. Therefore, payments received for construction reimbursement are not revenue-generating transactions and are to be treated as reductions to Cost of the constructed Assets.
b) If a CIAC is received from a non-customer, and ownership is retained by the Company, the CIAC is recorded as a liability and periodically offset against the Cost of construction. Any unsettled Residual balances may result in gains or losses but cannot be setup as Assets as the third-party payer is not a customer and therefore the physical Assets are not expected to provide future economic benefit to the Company.
c) If the CIAC is received from an existing customer on the Company's system for which reimbursement is being made and the Assets remain the property of the Company, the CIAC is considered part of the revenues similar to transportation tolls and therefore the reimbursement will be recorded as deferred revenue and treated separately from the Assets created. In such instances the reimbursement is not credited to the project. The resulting Assets are depreciated over the Useful Life of the Assets alongside similar Assets within that Company system and the deferred revenue is amortized over the term of the revenue contract.
d) If the CIAC is received from an existing customer on the Company's system for which reimbursement is being made, however the Asset ownership is transferred to the customer upon construction completion, similar to (c) above the reimbursement will be recorded as deferred revenue. The Cost of construction will be viewed as the Cost of obtaining the contract and recorded as other Assets instead of as Capital Assets on the balance sheet. This is because Asset ownership is transferred to the customer. Both the deferred revenue and the other Asset balance will be amortized over the same period in accordance with the remaining term of the revenue contract.

In situations where the Company makes up-front payments to electric utilities to fund the construction of transmission lines required in order to connect electricity to new pipelines or other projects, the refundable portion of those payments is accounted for as a current or non-current receivable.

The non-refundable portion of such payments is considered part of the Cost of bringing the Company's Assets to its intended use and is therefore Capitalized as part of the capital project.

10. Information technology hardware, software and internal use software

The Information technology category includes both hardware and software purchases, as well as internal use software, which is defined as software developed, acquired, or modified by the Company to meet its own internal requirements, as opposed to software purchased from a third-party vendor.

10.1 Hardware and software purchases

Hardware purchases and their associated implementation Costs are considered capital Costs. Software purchases from third parties are also considered capital as long as this software is installed on at on premise servers.

For guidance in regard to Costs incurred under Software as a Service arrangements including cloud computing where the Company does not obtain title to the software provided, please refer to *Appendix 3 – Directly Attributable capital Cost exclusions*.

10.2 Internal use software

Internal use software is acquired, internally developed, or modified solely to meet the entity's internal needs and regulatory requirements, and to streamline operations. In addition, no substantive plan exists to market the software externally.

Internal use software projects are subject to the most evaluation, as individual tasks undertaken within these projects must be classified as either capital or expense in nature. (Refer to *Appendix 2 – Directly Attributable capital Cost inclusions* and *Appendix 3 – Directly Attributable capital Cost exclusions* for additional guidance).

Internal Use projects can be typically divided into different stages and US GAAP provides detailed guidance on the accounting treatment of Costs at each stage

i. Preliminary project stage

Project activities undertaken at this stage include current stage assessments, preliminary design activities, vendor demonstrations, technology requirements and selection of vendors. All expenditures incurred at this stage are expensed per ASC 350-40-25-1. Additionally, Costs of consultants and the Company's internal staff (i.e., payroll and labor burden) are charged to expense during this stage.

ii. Application development stage

Once the project receives appropriate approval and funding and the project meets Capitalization criteria, the internal and external Costs incurred at this stage are accounted for according to the guidance set out in ASC 350-40-25-2 to 25-5.

The guidance allows for the Capitalization of certain Costs incurred which include Costs to purchase the software, external direct Costs of materials and services in developing/acquiring the internal use software, payroll and labor burden Costs for the time that individuals are working directly on the project and interest Costs incurred, etc.

However, there are certain Costs that are not eligible for Capitalization and must be expensed at the time the Cost is incurred. These include all Costs incurred relating to data conversion, training, software maintenance, unspecified upgrade agreements and General and administrative and overhead Costs (i.e. office services, finance and accounting, legal, and other similar Costs) as required by ASC 350-40-30-3.

Regulated Company entities are also to refer to applicable guidelines established by the regulator when determining if item should be treated as capital or expense.

iii. Post implementation/operation stage

Internal and external training and maintenance Costs are expensed as incurred per ASC 350-40-25-6.

10.3 Upgrades and enhancements

The Cost of upgrades and enhancements (modification) to existing internal use software may be Capitalized if the modification result in additional functionality which to enable the software to perform tasks that it previously was not capable of performing. A modification that only extends the Useful Life without adding additional functionality is a maintenance activity and is to be expensed as incurred. Any maintenance combined with the upgrade in a contract must be separated and expensed.

Business process reengineering Costs are not capital in nature and are expensed as per *Appendix 3 – Directly Attributable capital Cost exclusions*.

11. Cessation of Capitalization

Recognition of capital Costs on a project ceases when the project is in the location and condition necessary for it to operate in the manner intended. This is generally attained at the In-Service Date of the capital project. For multiple phase projects, each identifiable phase capable of functioning independently will cease Capitalization when it is ready for its intended use.

11.1 Trailing Costs

The Company undertakes large capital projects which may incur Costs for several years after the Asset has gone into service. Some of these expenditures may be necessary for the successful completion of the project and are to be Capitalized as part of the Cost of the Asset. For example, as a condition of regulatory approval, the Company may agree to do post construction environmental work on disturbed lands after the pipeline is in operation. Additionally, the timing of certain tasks necessary to complete a project may be dependent on factors such as weather or the availability of contractors or equipment.

11.2 Safety and Environmental Costs

Capital expenditures required to meet the Company's safety and environmental standards may be Capitalized when they contribute to Assets with lives spanning more than one year.

Environmental Restoration - Costs required to bring the project into service may be Capitalized.

Post Construction Environmental Monitoring - Estimated costs associated with the development of post construction environmental monitoring plans as well as the execution of those monitoring plans that are necessary to satisfy regulatory and stakeholder requirements may be Capitalized based on meeting the following criteria:

1. The regulators require the post construction environmental monitoring plan as a necessary condition for placing the project into service.
2. The cost associated with developing and implementing the plan over the term of the regulatory requirement is known or can be reasonably estimated.

Note: If the above criteria is not met, post construction environmental monitoring costs will be expensed as incurred.

Environmental Remediation - Work that is performed to remediate right of way restoration issues can be capitalized up to 2 years after the project has gone into service. Remediation costs incurred after this 2 year period is considered maintenance work and is therefore expensed.

12. Policy administration

The Director of Capital Assets of Enbridge Inc. is responsible for the overall administration of this Policy. The Director of Accounting Policies and Internal Controls is responsible for ensuring periodic reviews are conducted of this Policy. The Director of Capital Assets is responsible for regularly reporting to the CAO on exceptions arising from the Company's activities governed by the Policy.

All employees involved in the Capitalization of expenses are responsible for being familiar with and complying with this Policy. All aspects of non-compliance must be reported to the employee's immediate supervisor, Internal Controls and, as appropriate, to an employee in a higher Salary Grade in the business unit or to the Chief Accounting Office.

Inquiries regarding interpretation of the Policy or revisions to the Policy should be directed to the Capital Asset team. Any requests for revisions of this Policy are to be submitted to the Chief Accounting Office for consideration and will be reviewed by the Director of Capital Assets.

Any amendments to this Policy must be approved by CAO with the exception of the following which may be approved by the Director of Capital Assets:

- Amendments to correct errors, clarify meaning or intent or with respect to the administration of the Policy; and
- Any updates to the Appendices.

Appendix 1: Authoritative Guidance

Applicable US GAAP	ASC 340 Other Assets and Deferred Costs ASC 350 Intangibles – Goodwill and Other ASC 360 Property Plant & Equipment ASC 410 Asset Retirement and Environmental Obligations ASC 805 Business Combinations ASC 835 Interest ASC 845 Nonmonetary Transactions ASC 908 Airlines ASC 970 Real Estate - General

Appendix 2: Directly Attributable Capital Cost Inclusions

The following table identifies Costs which are typically included in capital but are not limited to. For additional guidance, please contact the Capital Assets team.

Access roads	Major repairs or resurfacing which increases Useful Life or a change in the surface (gravel to asphalt) or widening of a road can be Capitalized. All other minor repairs are to be expensed.
Allowance for interest and equity during construction	AIDC and AEDC on qualifying Assets (*Refer to Section 7.7 – Allowance for Funds Used During Construction (AFUDC) and Capitalized Interest*).
Base Pressure Gas - Company owned	Capitalize as PP&E as it is integral to the operation of the related Asset.
Cathodic protection (anodes, test boxes, ground beds, rectifiers)	Initial ground bed installations and the installation of additional rectifiers, anodes and ground beds are allowable to be Capitalized.
Contract work	Amounts paid for work performed under contract by other companies and individuals related to the approved scope of the project.
Costs of testing, including hydro testing during commissioning of new pipelines	Costs incurred while testing whether the Asset is functioning properly, after deducting any proceeds generated while bringing the Asset to its intended use.
Development of manuals	The initial development Costs of new manuals and operating procedures, including IT and operational manuals during the process of creating a new capital Asset, can be Capitalized. These manuals are created for internal use only and used on a continual basis. Any revisions or updates to manuals are expensed.
Drawings/mapping	The Cost of preparing initial drawings or of updating drawings to current standards is a necessary expenditure to construct the Asset, and is accordingly Capitalized through a direct charge to the project. The Costs of subsequent maintenance of drawings are to be expensed.
Engineering services and professional fees	Any amount paid to third parties including other companies, firms or individuals engaged by the Company to plan, design, prepare estimates, supervise, inspect or give general advice and assistance in connection with a construction project.
Geohazard remediation program	Certain Geohazard expenditures performed on the Company's existing right of way can be Capitalized. For detailed guidance, please refer to the Geohazard Remediation Program Memorandum.
Handling and delivery	Initial Handling and Delivery Costs (freight, etc.).
Insurance, injuries and damages	Premiums paid for insurance during construction. Costs incurred in respect of injuries to persons, damage to property of others and damage to plant incidental to construction. Insurance recovered or recoverable for compensation for the aforementioned items is to be credited to construction Costs.

IT hardware purchase	Hardware purchases and the associated implementation Costs are considered capital.
Labor and employee benefits	Labor Costs and benefits for those employees working directly on the construction or acquisition of the item of PP&E including management of front-line construction.
Land	Costs related to the acquisition of land are to be Capitalized if the Costs are directly identifiable with the purchase. Land will not be amortized.
Land rights, land permits, right of way	Costs related to the application and purchases of right of way are to be Capitalized.
Line lowering if units of plant are added	Cost may only be Capitalized if units of plant are added (e.g. Sections or joints of pipe equal to or greater than 1 meter or 3 feet in length) Cost of raising, lowering or relocating existing lines are expensed.
Linefill/Linepack- Company owned	Costs are Capitalized as non-depreciable PP&E as it is required to operate the pipeline. Volumes will remain in use in the pipeline until the pipeline is decommissioned. Subsequently, volumes would be sold at current market value.
Linefill/Linepack- Marketing company (i.e. Tidal Marketing)	These Costs are not capital. However, treatment of these Costs takes into account the terms of shipping agreement. • LT = Treated as a Non-Capital Long Term Asset • ST = Treated as Inventory
Linefill/Linepack- Shipper owned	Costs are not Capitalized
Materials and supplies	The purchase price of materials and supplies which includes import duties and non-refundable purchase taxes, after deducting trade discounts and rebates.
Other related Costs	Ad valorem taxes (i.e. taxes based on the value of imported goods), inspection Costs, insurance and transportation Costs (i.e. Costs of transporting workers, equipment and material and supplies used for construction purposes).
Privileges/temporary land use or rights	Compensation paid for the temporary use of public and private property in connection with a construction project.
Project management	Project management Costs directly related to the construction or acquisition activity.
Pump modifications - Impeller replacements	An impeller is a unit of plant and qualifies as a capital expenditure when a worn impeller is removed from service and replaced.
Pump modifications - Motor rewinds	If the re-wind is performed to increase efficiency to a point that is beyond the original design, then the re- wind and associated Costs are to be Capitalized. In all other situations, such Costs are to be expensed.
Pump modifications - Trimming of impellers	Capitalization is allowable if the change either increases pump efficiency or improves the overall pump capacity. Otherwise these Costs must be expensed.

Pump modifications - Volute modifications	Similar in nature to a trim. It is usually done as a Cost-effective modification to pumps to accommodate the pumping of a product that differs from the original pump design specifications.
Rents	Amounts paid for the use of temporary housing and office space occupied by project management personnel and construction crews and other incremental rental Costs such as equipment rentals incurred specifically in relation to a project that is not for the Company's own use are Capitalized. Rental Costs incurred to accommodate staff temporarily relocated while their offices or facilities undergo renovations (i.e. swing space) must be charged to expense as the property is for internal use.
Representation Costs	Representation Costs are defined as expenditures incurred in making a representation for the purpose of obtaining a license or permit relating to the capital project. For the Costs to be eligible for Capitalization, they must relate to representations to, or be required by, a government or government agency that has the authority to make rules, regulations or bylaws related to company operations. These Costs would include the Costs of preparing and processing applications, hearing Costs and related legal Costs.
Site preparation	Costs of site preparation including Costs incurred in disposing of excavated material (other than contaminated soil; see *Appendix 2 – Directly Attributable capital cost inclusions*) during the course of a capital project.
Software purchase	Software purchases from a third party are considered capital.
Special machine and heavy work equipment service	The Costs related to power shovels, scrapers, pile drivers, dredgers, ditchers, material loaders and similar equipment that paid to others for rent, operation and maintenance of such equipment can be Capitalized.
Tank painting and fibreglassing	Tank fibreglassing most frequently refers to floors but is also performed on roofs. The first application of fiberglass to any tank surface, whether done at time of initial construction or subsequent thereto, is to be included in PP&E as a capital Cost. The initial tank painting is considered a capital Cost of the construction project.
Transient analysis	Expenditures for transient pressure analysis during the construction stage of a project are Capitalized.
Vehicles	Purchase price plus any non-recoverable taxes.

Appendix 3: Directly Attributable Capital Cost exclusions

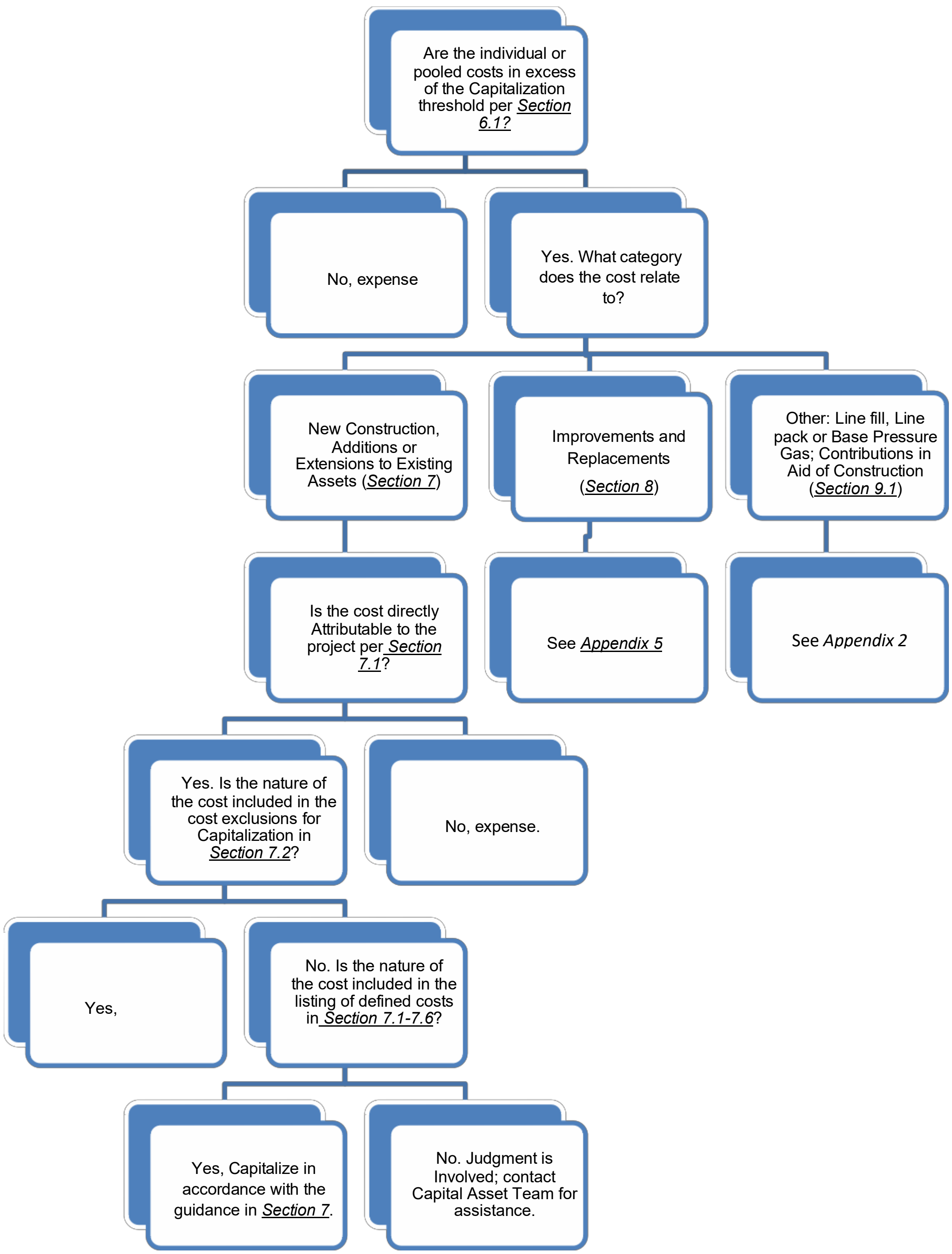
The following table identifies Costs which are excluded from capital but are not limited to. For additional guidance, please contact the capital Assets team.

Business process re-engineering	US GAAP specifies that the Costs of business process reengineering activities are to be expensed as incurred. Business process reengineering Costs that are expensed include: • Preparation of a request for proposal. • Current state assessment - the process of documenting the entity's current business processes. This activity is sometimes called mapping, developing an as-is baseline, flow charting, and determining current business process structure. • Process reengineering - the effort to reengineer business processes to increase efficiency and effectiveness. • Restructuring the work force - the effort to determine what employee composition is necessary to operate the reengineered business processes.
Charitable donations; sponsorships, social license or community investment paid to support a project	Charitable donations are payments made on an unconditional basis, and for which we do not receive any consideration in return; they are expensed as incurred. Some Sponsorships that derive direct benefit to a specific project can be Capitalized. Please refer to the Memorandum "Sponsorship and Donations Procedural Guidelines".
Cloud computing	Certain expenditures incurred in regard to cloud computing can be Capitalized. For detailed guidance, please refer to the Cloud Computing Memorandum.
Contaminated soils cleanup	In general, contaminated soil cleanup is to be charged to expense. US GAAP guidance allows Capitalization subject to a recoverability test, only if at least one of the following criteria is met: • The condition of the property is improved as compared with the condition of the property when originally constructed (or acquired, if later); or • The Costs are incurred in preparing the property for sale and the property is classified as "held for sale" on the balance sheet, subject to a recoverability test. Cleanup Costs may also be eligible for Capitalization in situations where the soil has been contaminated by a third party prior to the Company obtaining its right of way, and construction cannot occur unless the contaminated soil is remediated.
Equipment tagging and data	Equipment tagging uses a Company-specific label that is attached to each identifiable piece of equipment. This serves the function of a serial number, whereby information on that piece of equipment can be pulled up and reviewed by Operations for maintenance purposes. Equipment data is the actual vendor-specific information entered into the maintenance management system. As these Costs are viewed as ongoing record management for maintenance of the capital Assets, the Costs are expensed.

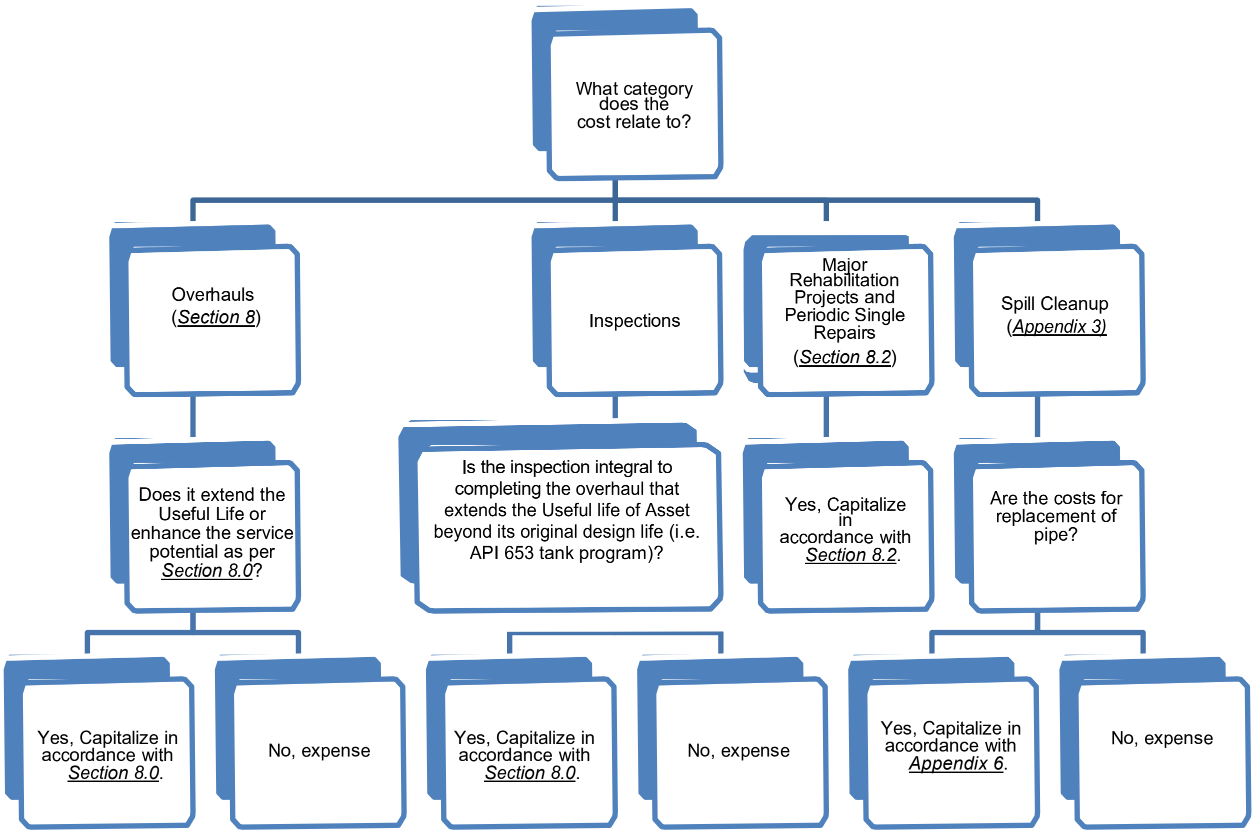
General and administrative Costs not Directly Attributable to capital projects	General and administrative Costs which are not Directly Attributable to capital projects are expensed as incurred. This would include items such as office support services, human resources, IT, accounting, legal, and executive Costs which are not chargeable to a capital project. For clarity, general and administrative Costs may only be Capitalized in accordance with *Section 7.5 – Overhead-related Costs* (Some G&A Costs may be Capitalized according to rate regulated rules or guidelines).
Initial operating losses	Losses incurred during the period after the Asset is available and, in the condition, necessary for its intended use but before it reaches its commercial operation date, are recognized in income.
Internal use software – Application development stage	Data conversion (other than software Costs as discussed above). The process of data conversion from old to new systems may include purging or cleansing of existing data, reconciliation or balancing of the old data with data in the new system, creation of new/additional data, and conversion of old data to the new system. Software maintenance and unspecified upgrade agreements are frequently entered into at the time of initial purchase but are not to be considered part of the capital Cost of the project. These Costs are expensed in the period in which they are incurred. Agreements which provide support in future fiscal years should be treated as a prepaid expense which is amortized to expense over the term of the agreement. Costs incurred after the point at which a computer software project is complete and ready for its intended use (i.e., after all substantial testing is complete) are expensed. General and administrative and overhead Costs are addressed separately within *Appendix 3 – Directly Attributable capital Cost exclusions*.
Membership and professional dues	These Costs are expensed as they are incurred.
Spill cleanup and environmental remediation Costs	Expenditures incurred because of a line break and subsequent oil spill are charged to expense as incurred as such expenditures do not generate any future economic benefits to the Company. Costs incurred in relation to environmental remediation related to a spill are also expensed. However, an exception to this general rule may be made where any portion of the pipeline or associated equipment is replaced because of a line break or spill. In that case, the Cost of the replacement is Capitalized, and the undepreciated Cost of the replaced Asset is expensed in accordance with the relevant provisions of this Policy. If Group Method of Depreciation is applied to the replaced Asset, the Cost is instead recorded to accumulated Depreciation.
Start-up Costs and expenditures for commencing new operations	Start-up Costs such as advertising, organization Costs, including governmental charges and legal and professional fees relating to the commencement of a new operation (e.g. new facility, Asset, or plant) are expensed.

Training Costs of employees or consultants	The Costs of ongoing training of employees or consultants are expensed as incurred. This would include travel Costs for the trainer and end-user to attend training courses, the value of their time spent while training, the Cost of developing training courses and the Cost of the facilities and equipment used for training. See *Appendix 2 – Directly Attributable capital Cost inclusions* which discusses the development of (training) manuals, which may be Capitalized in some situations.

Appendix 4: Decision Tree for Capitalization



Appendix 5: Decision Tree for Improvements and Replacements



Appendix 6: Pipeline Maintenance and Repair Guideline

Assessment Activities	Major Rehabilitation Project[1]
Pipeline Integrity Runs (Corrosion, Crack Detection and deformation tools)	Expense
Hydro tests	Expense
Construction Activities	
Replacement: One Unit of Property[2] or Greater	Capital
Replacement: Less than One Unit of Property[2]	Expense
Sleeving[3]	Capital
Recoating[3]	Capital
Rewrapping	Capital

1. Integrity Programs classified as Major Rehabilitation Projects extend the overall pipeline system's Useful Life and serviceability.
2. Unless governing regulatory authorities require another measure, Unit of Property for pipeline is 1 meter
3. Currently, pipe recoating or sleeving is the preferred method of repair in Major Rehabilitation Projects. Recoating is capitalized when it extends the Useful Life of the pipeline. Hydro testing of pipe during the commissioning phase of a project is capitalized

CAPITALIZATION OF OVERHEAD

COLIN HEALEY, DIRECTOR FINANCIAL PLANNING & ANALYSIS

1. The purpose of this evidence is to request OEB-approval for Enbridge Gas's harmonized overhead capitalization methodology and resulting capitalized overhead amounts for the 2024 Test Year. This evidence summarizes the overhead capitalization methodologies previously in place for EGD and Union. This evidence also sets out the harmonized overhead capitalization methodology, identifies how the harmonized overhead capitalization methodology addresses OEB guidelines, accounting standards and other relevant policies, and summarizes the change in capitalization resulting from application of the harmonized overhead capitalization methodology. Ernst & Young (EY) was retained by Enbridge Gas to assist management in its determination of the Company's harmonized overhead capitalization methodology.

2. Enbridge Gas is also requesting approval of the amounts contained within the Accounting Policy Change Deferral Account (APCDA) associated with the change in overhead capitalization methodology adopted in 2020. This evidence details the 2020 and 2021 actual amounts, along with the 2022 and 2023 forecasted amounts, determined by comparing the overhead capitalization methodologies of EGD and Union to the Enbridge Gas harmonized overhead capitalization methodology. Please see Exhibit 9, Tab 2, Schedule 1, Attachment 3 for the resulting revenue requirement impact recorded in the APCDA.

3. This evidence is organized as follows:
    1. Background and Purpose of Overhead Capitalization
    2. History of Overhead Capitalization
    3. Proposed Harmonized Methodology

4. Comparison to EGD and Union Methodologies
5. Impact of Methodology Change (including APCDA)
6. Allocation of Capitalized Overheads to Plant Assets
7. Summary

1. Background and Purpose of Overhead Capitalization

4. The objective of overhead capitalization is to ensure all indirect costs associated with the creation of capital assets are captured as part of the asset cost. Costs that are directly related to asset creation (e.g., construction labour costs, materials/supplies) are identifiable and directly assigned to the appropriate capital projects. These costs are not subject to overhead capitalization. Indirect overhead are costs associated with the activities that support asset creation but cannot be directly associated with any particular asset or asset group. Indirect overhead costs include, but are not limited to, supervision and oversight of capital activities or support functions such as Finance, Legal, Supply Chain, Human Resources, Technology and Information Services (TIS), etc. Cost drivers are used to associate indirect overhead costs with capital activity.

5. Overhead capitalization has historically been in place at EGD and Union based on separate and distinct OEB-approved methodologies. The amalgamation of EGD and Union, effective on January 1, 2019, required an alignment of accounting policies. The capitalization of indirect overheads was one such area of alignment to provide a harmonized approach for the Company that meets the guidelines specified by the OEB Uniform System of Accounts for Class A Gas Utilities, and US GAAP.

2. History of Overhead Capitalization

6. Prior to amalgamation, EGD and Union applied overhead capitalization methodologies that were approved by the OEB and conformed to US GAAP. The following sub-sections establish the underlying regulatory approvals, the cost categories, and cost drivers for each of the pre-amalgamated Company's methodologies. Cost category represents a grouping of costs based on the inherent nature of the cost. Cost drivers are determined by the nature of the underlying causal activity and ultimately determine the degree of capitalization.

2.1. EGD Overhead Capitalization

7. EGD's overhead capitalization methodology prior to amalgamation consisted of two categories: Capitalized Administrative & General Overhead (A&G) and Departmental Labour Costs (DLC).

8. A&G represented common services that support capital activities. The OEB-approved methodology and rates were applied to A&G costs, such as Finance, Legal, Supply Chain, Human Resources, Benefits and TIS, to determine a total amount of A&G eligible for capitalization. The total amount was then allocated to capital projects proportionally based on capital expenditures.

9. DLC were salaries and employee expenses for the departments within Operations and Engineering where the respective functions of these departments contributed to capital projects but were not directly attributable to specific capital projects. Examples of these functions include system capacity planning, distribution plant drafting, pipeline inspection, field operations, customer attachment and records management. Capitalization rates were applied to each eligible department's O&M and allocated to Mains, Services and Measurement and Regulation assets. Any

costs within A&G and DLC, that were directly tied to capital projects, were directly charged and not subject to overhead capitalization.

10. A&G capitalization rates were determined by cost drivers based on the classification of activities into the following three types:

    a) Consultative: This cost type refers to activities of a 'consulting' nature where the activity is primarily project-specific and the level of activity is not consistent year-over-year. Examples of such activities would be found in functions such as Legal services or Finance. The use of time is considered practical and appropriate as the driver for these activities and provides the strongest link between costs and services provided.
    b) Administrative: This cost type refers to activities that support other activities. Examples of support activities include functions performed by administrative support staff (e.g., mail distribution, telephone support, etc.) and in some cases department management. As these activities and related costs typically directly support other activities, they are usually best allocated in the same proportion as the activities which they are supporting.
    c) Repetitive: This cost type refers to activities that are repetitive in nature and are consistent over time in terms of the level of effort per unit of service provided. Examples of such activities are Payroll, Human Resources, and Accounts Payable. Processes are standardized and consistent and costs track accordingly. As such, this category of costs is best allocated based on volumetric measures reflecting or causing the activity to be performed and therefore the cost to be incurred. For example, headcount related to the various programs or capital assets is a suitable driver for Human Resource support or the Payroll function.

11. OEB approval of the A&G methodology was granted in 1998 as part of the 1999 Test Year Rates Application[1]. The Application detailed the capitalization study undertaken and formalized the definitions and approach for A&G. Subsequent settlement agreements and OEB decisions have approved the continued application of the A&G methodology. The DLC capitalization methodology has been referenced and included in the determination of O&M and capital submissions that have received OEB approval. A&G and DLC were most recently approved in 2012 as part of the 2013 Cost of Service Application Settlement Agreement[2] and in 2014 as part of the 2014 to 2018 IRM Application[3].

2.2. Union Overhead Capitalization

12. Union's overhead capitalization methodology prior to amalgamation consisted of two categories: Loadings and Indirect Overhead.

13. Loadings are costs that can be attributable to capital activity, but due to the nature of the costs, it is difficult to allocate them to specific projects. These costs included benefits and incentive pay, non-productive labour (i.e., vacation and sick time), fleet maintenance, fleet depreciation, planning and dispatch, construction oversight and warehouse costs. A Loadings rate was used to assign these costs to specific capital projects based on the labour charged to the specific capital projects.

14. Indirect Overhead are costs that support the production or construction of an asset but cannot easily be directly associated with any particular asset or working group. These costs can be broken down as:

[1] In E.B.R.O 497 Decision, Issue 3.8.
[2] In EB-2011-0354, Settlement Agreement, Issue B.1 (Capital Expenditure) and Issue D.1 (O&M).
[3] In EB-2012-0459, OEB Decision, pp.30-33 (Capital Expenditure) and pp.44-51 (Other O&M).

a) Specific Capital costs which include evaluation, design, and implementation related to capital projects generally rather than to specific or identifiable projects;
b) Supervision costs which represent functions that support, supervise, and monitor direct project activities; and
c) Support Functions which include budgeting and reporting, building maintenance, TIS help desk, Human Resources, Strategic Development, Procurement, Plant Accounting, and Accounts Payable.

15. Overhead capitalization rates were determined by an appropriate cost driver for each department with costs eligible for capitalization. The four cost drivers were as follows:
    a) Time Analysis: An estimate was developed by the managers of each individual department to allocate each employee’s time between capital and O&M. A weighted average of capital to O&M time was calculated among all employees in the department and applied to all costs.
    b) Work Plan: Support costs related to tasks carried out by front-line workers were allocated using a work plan. The work plan represented the type and volume of “jobs” that related to capital activity versus general O&M activity. As individuals within these groups supported front-line workers directly, their time was highly correlated to capital activity.
    c) Volume or Other: In certain situations, unit-based measures of work related to capital (such as for warehousing) or total capital spend relative to total spend (capital and O&M combined) was used as a way to determine how much of that department’s costs were capital in nature.
    d) Composite Ratio: For support functions, departments and groups within the Company that supported various other parts of the business, a composite ratio was used to determine the rate at which overhead was capitalized.

16. Approval of Union's overhead capitalization methodology was obtained in 2006 as part of the 2007 Cost of Service Application[4] Settlement Agreement. Union submitted an update to the methodology, which was implemented in 2010, and approved as part of the 2013 Cost of Service Application[5] Settlement Agreement. The update introduced "Loadings" which facilitated the direct assignment of certain capitalized overheads to capital projects. The update was not deemed to be a change in the capitalization policy.

3. Proposed Harmonized Methodology

17. Prior to amalgamation, EGD and Union applied different OEB-approved overhead capitalization methodologies that used similar underlying principles, cost categories and cost drivers. As an amalgamated company, it was necessary for Enbridge Gas to establish a harmonized methodology that aligned to the Company's new structure and assess how the functional groupings contributed to capital activity.

18. Enbridge Gas retained EY to assist management in its determination of a harmonized capitalization methodology. EY was informed by the historical methodologies of EGD and Union, Enbridge Gas's structure and relevant accounting guidance. EY's assessment is documented in a report entitled "Enbridge Gas Inc: Overhead Capitalization Study" (EY Study). This report is provided at Attachment 1. The harmonized capitalization methodology was implemented January 1, 2020.

[4] In EB-2005-0520 Settlement Agreement, Issue 3.11.
[5] In EB-2011-0210 Settlement Agreement, Issue 3.1.

19. The following sub-sections outline the harmonized methodology's guiding principles and development, accounting guidance supporting overhead capitalization, cost categories and drivers, and the process to update overhead capitalization rates.

3.1. Guiding Principles and Development

20. For the harmonized overhead capitalization methodology to reflect the amalgamated operations of Enbridge Gas, the following guiding principles were identified:
    a) Establish a single, consistent methodology for Enbridge Gas;
    b) Promote accuracy and transparency through a streamlined model that reflects the underlying capital activity;
    c) Support the practical implementation of the model allowing for regular (annual) updates; and
    d) Comply with accounting standards and OEB policies.

    Application of these guiding principles result in a methodology that appropriately accounts for the geographical diversity of Enbridge Gas's operations and provides a consistent approach in determining how each department or function supports capital activity.

21. In helping management develop the methodology, EY used a combined approach of relying on accounting guidance, cost causation linkages (including the identification of cost categories and drivers), discussions with Enbridge Gas personnel, and understanding industry best practices. Further overview on accounting guidance and cost categories, drivers and causality can be found in Sub-Sections 3.2 Accounting Guidance and 3.3 Cost Categories and Cost Drivers for the EY Study.

3.2. Accounting Guidance

22. Overhead capitalization is allowable based on the accounting guidance noted in Section VI of the EY Study. The OEB's Uniform System of Accounts provides support for this conclusion in the Overhead Charged to Construction section of Appendix A. US GAAP Accounting Standards Codification (ASC) 360 – Property, Plant, and Equipment specifies that asset capitalization includes "costs incurred for activities to bring them to the condition and location necessary for their intended use". Furthermore, US GAAP ASC-980 – Regulated Operations allows the capitalization of overhead costs if future recovery through rates is probable. As provided at Exhibit 2, Tab 4, Schedule 1, Enbridge Gas is requesting approval to continue capitalizing overheads, as previously approved by the OEB for EGD and Union.

3.3. Cost Categories and Cost Drivers

23. The harmonized overhead capitalization methodology uses four cost categories. These categories are Operations Costs, Business Costs, Shared Services Costs and Pension and Benefits Costs. Each cost category has a cost driver applied, typically determined by the nature of the underlying cost relationship or linkage to capital activity. Cost drivers include capital expenditures, time analysis, weighted average rates, and burdening. Please see pages 6-9 and pages 15-16 of the EY Study for additional detail.

Operations Costs

24. The Operations Costs category consists of groups that support Enbridge Gas's core field operations within the Company's seven geographic regions which were realigned post amalgamation. These groups provide oversight for and support direct capital activity related to the natural gas delivery infrastructure.

25. To determine overhead capitalization for the Operations Costs category, the following methodology is applied:
    a) Operations Regional groups apply each region's proportion of capital spending, resulting in seven separate rates. Due to the diversity of each region, both in geographic features (i.e., urban and rural) and infrastructure, it was concluded that allocation rates for each region would best reflect the capitalizable portion of overhead. Regional capital spend was determined to be an appropriate driver as it represents the actual allocation of labour and material resources by Enbridge Gas to capital projects versus O&M.
    b) Operations Services and Governance (OSG) group (excluding 'c' and 'd'), which provides support services to the regions, uses a weighted average of the seven Operations Regional rates.
    c) Customer Attachment group is considered 100% capital due to the fully capitalizable nature of activity supported.
    d) Leak Survey and Locates are considered 100% O&M as they are preventative measures not contributing to asset creation.[6]
    e) Operations VP Admin uses a weighted average of the preceding rates in a), b), c) and d).

Business Costs

26. The Business Costs category includes certain departments/groups within Enbridge Gas that support core operations. Although their work can be linked to capital activity, it cannot be directly associated with any particular asset or asset group. Examples of these support areas include Engineering, Asset Management, System Improvement, and Integrity. Time spent on work was determined to be an

[6] Locate costs are included in O&M in the 2024 Test Year Forecast. As a result of Bill 93, other utilities may begin charging Enbridge Gas for locate delivery services for its own operations. At which time, a portion of the locate costs may be capitalized.

appropriate driver given the varied nature of these groups and their activities. Time analysis is necessary to appropriately identify the relationship between the functions of these groups and capital activities.

27. To determine overhead capitalization for the Business Costs category, the following time analysis methodology is conducted annually:
    a) Managers in the groups identified in this cost category identify all the activities carried out by their teams. Each employee's time is allocated among the various activities in an activity template. The activities are classified as Capital or O&M based on US GAAP and OEB guidance.
    b) A weighted average rate of capital time relative to O&M time is calculated using the employee activities within the manager group.
    c) Each resulting rate per manager group is grouped within their respective director group and weighted to derive an average rate for the director group.
    d) Validation is performed within each director group using a comparison of the current and prior year director level rates. For any significant increases or decreases, activities are reviewed to identify key activities driving the change and assess if their categorization is appropriate.
    e) Director level weighted average rate is applied to all costs incurred within the director group to determine the overhead capitalization amount.

Shared Services Costs

28. The Shared Services Costs category contains groups that support overall business activities including general functions required to complete capital projects. Examples of these services are Finance, Legal, Real Estate and Workplace Services, TIS, etc. Human Resources employee labour costs and related expenses are included in this category, and Pension and Benefits costs are treated separately (see Pension and Benefits Costs below). Shared Service Costs are incurred by

Enbridge Gas through the Central Functions Cost Allocation Model (CFCAM). EY's report categorizes Shared Services and CFCAM costs as separate overhead capitalization categories. However, as the Central Functions departments within Enbridge evolved post-merger with Spectra Energy, most Shared Services costs are incurred by Enbridge Gas via CFCAM. Therefore, they are combined in this evidence except for Pension and Benefits. Please see Exhibit 4, Tab 4, Schedule 3 Program Delivery Costs and Variance Analysis for more detail on CFCAM.

29. For Shared Services Costs, a single overhead capitalization rate was calculated by taking a weighted average of Operations Costs and Business Costs rates and non-capitalizable costs (groups that do not support capital activity). A single rate was determined to be most appropriate for overhead capitalization as the groups in this cost category support all of the business activities of Enbridge Gas.

Pension and Benefits Costs

30. The Pension and Benefits Costs category contains pension and benefits incurred by Enbridge Gas. In the context of this evidence, benefits are defined as Short-Term Incentive Pay (STIP), Long-Term Incentive Pay (LTIP) and employee medical, dental, disability and statutory benefits as provided at Exhibit 2, Tab 4, Schedule 3. For labour that is directly charged to capital projects, a burden rate for pension and benefits is applied to appropriately reflect the entire compensation cost associated with employees. Pension and benefits costs for indirect labour need to be similarly treated as the same cost relationship exists. Salary grade burden rates provided by Human Resources are used as an input to calculate a single weighted average burden rate for all employees. The weighted average burden rate is determined by:

a) Calculating capitalized labour by applying the capitalization rate to gross labour costs for each employee (based on the cost categories identified in Operations Costs, Business Costs and Shared Services Costs). The results are summarized by salary grade excluding directors and above and contractors to reflect only employees likely to be involved with capital activity.
b) Associating the current year's burden rate, obtained from Enbridge Gas Human Resources, with each eligible salary grade. Please see Exhibit 2, Tab 4, Schedule 3 for further information on the Human Resources burden rate.
c) Calculating the single Enbridge Gas burden rate by taking a weighted average of the salary grade burden rates from (b) and weighing it by the proportion of capitalized labour from (a).

The single weighted average burden rate allows for ease of application across all direct and indirect capitalized labour, regardless of employee salary grade, as part of the burdening process to layer on pension and benefits.

31. Enbridge Gas's harmonized overhead capitalization methodology calculates a weighted average burden rate of 41.7% for the 2024 Test Year budget. The weighted average burden rate more appropriately capitalizes pension and benefits costs because it is applied to the capitalized labour. This results in a better association of total employee compensation to capital activity as employee involvement in capital activity shifts annually. Table 1 outlines the calculation used to determine the harmonized weighted average burden rate.

Table 1
Pension and Benefits Burden Rate Calculation

Line No.	Organizational Level	2024 Test Year HR Burden Rate	Weighting	EGI Burden Rate
		(a)	(b)	(c)
1	E310 – Clerical	42.4%	0.1%	0.1%
2	E320 – Clerical / Technical	45.1%	1.1%	0.5%
3	E400 – Technical / Professional	43.4%	2.0%	0.9%
4	E410 – Technical / Professional	41.9%	8.0%	3.3%
5	E420 – Technical / Professional	40.5%	19.4%	7.9%
6	E500 – Specialist	44.2%	9.8%	4.3%
7	E510 – Specialist	43.1%	14.9%	6.4%
8	E600 – Manager	61.5%	5.7%	3.5%
9	Unionized Staff	38.1%	39.0%	14.8%
10	Total			41.7%

Notes:

(1) Weighting in column (b) calculated using estimated capitalized labour for each organization level as a proportion of total estimated capitalized labour.

3.4 Update Process

32. To ensure that the overhead capitalization rates closely reflect the underlying capital activity, the inputs to harmonized methodology are updated annually. Calculations are carried out on the latest actuals and applied to the prospective year. For instance, capitalization rates applied in 2022 are based on the 2020 actuals as those would have been the most recent actuals at the time the 2022 budget is prepared. Identical capitalization rates are applied for both actuals and budget within the same year. Capitalization for the 2024 Test Year is based on 2021 actuals and are identical to those used for the 2023 budget.

4. Comparison to EGD and Union Methodologies

33. EGD and Union previously applied separate overhead capitalization methodologies that identified cost categories, drivers and causal relationships relevant to each

company. The amalgamation provided an opportunity to streamline and improve the efficiency of the previously approved methodologies into a harmonized methodology that complies with relevant accounting and OEB guidance. Table 2 depicts how the cost categories from the prior methodologies align to the harmonized methodology.

Table 2
Harmonized and Historical Cost Category Alignment

Harmonized Cost Categories	Historical Cost Categories					
	EGD		Union			
	DLC	A&G	Loadings	Specific	Supervision	Support Functions
Operations Costs	X		X		X	
Business Costs	X			X	X	
Shared Services Costs		X		X		X
Pension & Benefits Costs		X	X			

34. EGD’s DLC cost category, which was primarily comprised of Operations and Engineering costs, is now captured under the Operations and Business cost categories in the harmonized methodology. The A&G cost category, which was comprised of common or support costs, is now captured under the Shared Services and Pension & Benefits cost categories.

35. Union’s Loadings cost category, which included benefits and incentive pay, non-productive labour (i.e., vacation and sick time), fleet maintenance, fleet depreciation, planning and dispatch, construction oversight and warehouse costs, is now captured under the Operations and Pension & Benefits cost categories depending on the nature of the cost. Union’s Indirect Overhead cost category could be broken down into Specific, Supervision and Support costs. Specific, which included evaluation, design, and implementation costs, is now captured under the

Business and Shared Services cost categories. Supervision, which included support and monitoring costs for direct capital activity, is now captured under the Operations and Business cost categories. Support, which included costs for functions that provided overall support to business activities, is now captured under the Shared Services cost category.

36. By aligning cost categories and assigning appropriate drivers, the harmonized methodology better accounts for the geographical diversity of Enbridge Gas's operations and provides a consistent approach in determining how each department or function supports capital activity. The methodology also improved efficiency by simplifying the calculation of capitalization rates which reduces the number of capitalization rates that need to be maintained. For example, Operations Regional and Director level rates, Business Unit Director level rates, a single Shared Services rate and a single Pension and Benefits burden are simpler to update on an annual basis as opposed to capitalization rates set using more financial segments. Fewer rates also make system updating less complicated and allow for better understanding and visibility of departmental financial results.

37. Table 3 compares capitalized overhead by cost category under the harmonized methodology to the EGD and Union methodologies using 2024 Test Year costs. The calculation of capitalized overhead using prior methodologies was performed by applying the combined EGD and Union capitalization rates based on the proportion of capitalization for each department to the eligible 2024 Test Year costs. These proportional calculations were performed using the 2020 budget which was the last instance where the previously approved OEB capitalization rates were used.

Table 3
Comparison of Overhead Capitalization Methodologies - 2024 Test Year

Line No.	Particulars ($ millions)	Historical Method Capitalized Amount	Historical Method Capitalization Rate	EGI Harmonized Method Capitalized Amount	EGI Harmonized Method Capitalizatio n Rate	Variance Capitalized Amount
		(a)	(b)	(c)	(d)	(c) - (a)
1	Operations Costs	121.9	36.0%	118.2	35.0%	(3.6)
2	Business Units Costs	56.1	11.1%	54.5	10.8%	(1.6)
3	Shared Services Costs	63.8	20.5%	72.7	23.4%	8.8
4	Pension & Benefits Costs (1)	53.2	35.9%	65.1	43.9%	11.9
5	Total	295.1	22.7%	310.5	23.8%	15.4

Notes:

(1) Pension and Benefits costs include total net periodic pension costs and postretirement benefit costs to align with utility income statement presentation, however only the service cost component is eligible for capitalization. The capitalization rates after removing the non-service cost components of pension and OPEB are 23.9% for the historical methodologies and 29.3% for the harmonized methodology.

38. The harmonized methodology results in total overhead capitalization of $310.5 million for the 2024 Test Year, which represents an overall capitalization rate of 23.8%. The prior methodologies used by EGD and Union would have resulted in total overhead capitalization of $295.1 million which represent an overall capitalization rate of 22.7%. The net change is an increase of $15.4 million in overhead capitalization and 1.1% in the overall capitalization rate. The main drivers of the increase in capitalization are discussed below.

39. Operations Costs $3.6 million decrease in capitalization is primarily due to the harmonized methodology resulting in lower regional capitalization rates based on the proportion of capital spend to total spend. The lower regional rates reduced Regional Operations capitalization by $9.7 million. This was offset by higher support services (OSG and VP Admin) capitalization of $6.1 million resulting from the harmonized methodologies weighted average of regional capitalization rate being higher than the previously approved rates. OSG and VP Admin capitalization is now

more reflective of the groups they support as their rate is a weighted average of the Regional Operations rates.

40. Business Unit Costs capitalization has remained stable with a $1.6 million decrease. Historical rates and harmonized rates were closely aligned after conducting a time analysis for the functions in this costs category.

41. Shared Service Costs $8.8 million increase in capitalization is primarily due to a 2.9% higher harmonized weighted average rate as compared to previously approved rates. The harmonized methodology better associates EGI's level of capital activity built into Operations and Business Unit rates and the Shared Services that support those groups.

42. Pension and Benefits Costs $11.9 million increase in capitalization is primarily due to the introduction of a weighted average burden rate that reflects all components of employee compensation apart from base salary. Furthermore, the burden rate is applied to all direct and indirect capitalized labour. In Attachment 1, page 16, EY asserts that burdening is one of the most evident forms of cost causality that allows for associating pension and benefits with capitalized labour.

5. Impact of Methodology Change (including APCDA)

43. The Accounting Policy Change Deferral Account (APCDA) was established as an outcome of the MAADs proceeding to record the impact of accounting policy changes. The APCDA amount for overhead capitalization changes is calculated as the difference between the capitalization rates from the EGD and Union methodologies and the capitalization rates from the harmonized methodology, applied to each respective year's cost base since implementation in 2020. Table 4 outlines the actual O&M impact for 2020 and 2021, along with the forecasted O&M

impact for 2022 and 2023. Please see Exhibit 9, Tab 2, Schedule 1 for the resulting revenue requirement impact recorded in the APCDA.

Table 4
Change in Overhead Capitalization Methodology - O&M Impact

Line No.	Particulars ($ millions)	Utility	2020 Actual	2021 Actual	2022 Estimate	2023 Bridge Year
			(a)	(b)	(c)	(d)
1	EGI Harmonized Methodology	EGI	(224.3)	(234.2)	(268.9)	(301.1)
2	Historical Methodology	EGI	(218.7)	(228.0)	(260.0)	(284.4)
3	O&M Impact	EGI	(5.6)	(6.2)	(8.9)	(16.6)

Notes:
(1) Negative amounts represent a decrease to Operating & Maintenance (O&M) expense and an increase to capital expenditures

44. The impact from the change in overhead capitalization is a reduction in O&M because of an increase in overhead capitalization under the harmonized methodology due to a higher average capitalization rate. This higher average capitalization rate is primarily driven by the harmonized weighted average Shared Service rate and weighted average burden rate for Pension and Benefits as outlined in Section 4 of this evidence. From 2020 to 2023, the magnitude of the change increases from $5.6 million to $16.6 million because of increasing overhead capitalization rates as capital expenditures increase and an increasing pool of eligible capitalizable costs as gross O&M is forecasted to increase. Exhibit 4, Tab 4, Schedule 2 provides details on gross O&M.

6. Allocation of Capitalized Overheads to Plant Assets

45. Historically, EGD and Union allocated capitalized overheads to assets using different methods. EGD allocated based on cost category. A&G overheads were allocated proportionally to projects based on actual monthly capital expenditures

and as a result, were attributed to specific plant assets. DLC was allocated to Mains, Services and Measurement and Regulation asset classes based on the nature of work typically performed by the source departments or functions. Union allocated capitalized overheads to individual plant assets based on forecasted capital expenditures for the corresponding year. The individual plant assets were based on the asset groups defined by the OEB (Distribution, Storage, Transmission and General Plant).

46. A specific allocation of capitalized overheads to projects would be the most precise method; however, this is administratively difficult to implement as overheads are collected as a pool of costs and are not directly attributable to specific projects. As such, the Union approach of allocating capitalized overheads based on forecasted capital additions by asset class was adopted for both the EGD and Union rate zones. The Union approach offers the following benefits compared to the EGD approach:

    a) Aligns capitalized overhead to the asset classes they are supporting in a given year.
    b) Administrative ease and cost of implementation.
    c) Annual adjustments to allocations based on forecasted capital.

The capitalized overhead allocation methodology was reviewed in 2021 to ensure that it aligned with the EY Study. The revised allocation methodology was implemented in 2021 for the EGD rate zone with no change in process for the Union rate zone. The change in allocation resulted in a $1.0 million increase to depreciation expense in 2021 which is immaterial in terms of total depreciation expense for Enbridge Gas. The amount was not recorded in the APCDA as this is a change in estimate and not a change in policy.

47. Enbridge Gas is proposing to align the presentation of overheads as part of PPE reporting. Enbridge Gas intends to eliminate the use of regulatory overhead asset accounts for the Union rate zone and adopt the EGD rate zone approach of presenting capitalized overheads within PPE asset classes. The December 31, 2023, balances of Union rate zones' regulatory overhead asset accounts will start being presented within the related asset groups on January 1, 2024, in alignment with the implementation of the new depreciation study provided at Exhibit 4, Tab 5, Schedule 1, Attachment 1. This presentation change results in an immaterial impact to depreciation expense as the depreciation rates of the Union rate zone's regulatory overhead asset accounts historically already represented the average for each asset group.

7. Summary

48. Enbridge Gas's harmonized overhead capitalization policy delivers an approach consistent with the previous OEB-approved methodologies, the guiding principles set out prior to the development process and relevant accounting guidance. The cost categories identified best reflect the Company's organizational structure, functions and geographical diversity which allows for the assignment of appropriate costs drivers. The result is an improvement in the causal linkage between overhead costs and capital activity, along with a more efficient process of updating inputs annually.

Ernst & Young LLP (EY) prepared the attached Report only for Enbridge Gas Inc. (Client) pursuant to an agreement solely between EY and Client. EY did not perform its services on behalf of or to serve the needs of any other person or entity. Accordingly, EY expressly disclaims any duties or obligations to any other person or entity based on its use of the attached Report. Any other person or entity must perform its own due diligence inquiries and procedures for all purposes, including, but not limited to, satisfying itself as to the financial condition and control environment of Client, as well as the appropriateness of the accounting for any particular situation addressed by the Report.

EY did not perform an audit, review, examination or other form of attestation (as those terms are identified by CPA Canada, the AICPA or by the Public Company Accounting Oversight Board) of Client's financial statements. Accordingly, EY did not express any form of assurance on Client's accounting matters, financial statements, any financial or other information or internal controls. EY did not conclude on the appropriate accounting treatment based on specific facts or recommend which accounting policy/treatment Client should select or adopt.

The observations relating to accounting matters that EY provided to Client were designed to assist Client in reaching its own conclusions and do not constitute our concurrence with or support of Client's accounting or reporting. Client alone is responsible for the preparation of its financial statements, including all of the judgments inherent in preparing them.
This information is not intended or written to be used, and it may not be used, for the purpose of avoiding penalties that may be imposed on a taxpayer.

Enbridge Gas Inc: Overhead Capitalization Study

15 May 2020

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I. Executive summary

EY was retained by Enbridge Gas Inc. (Company or EGI) to assist management in its determination of the Company's harmonized capitalization methodology, subsequent to a January 2019 amalgamation of Enbridge Gas Distribution (Enbridge Gas or EGD) and Union Gas Limited (Union Gas or UGL).

EY obtained an understanding of the current practices and methodology at the legacy entities, EGD and UGL. As part of our assistance to management in documenting a comprehensive overhead capitalization methodology for EGI, EY then utilized a combined approach of relying on accounting guidance, cost causation linkage, discussions with EGI personnel, and understanding industry best practices. Through these procedures, EY developed a better understanding of the nature of costs incurred, the causation of these costs as they relate to capital activity, and the criteria by which capital allocations are determined.

Based on our interviews with staff, EY observed that the updated methodology for EGI incorporates various cost drivers that management has determined to best represent capital activity. EY documented management's rationale in determining the cost drivers, basis for allocations, and causality to capital projects. Further, as a result of the amalgamation and change in organizational structure, the Company determined that a harmonization of the indirect overhead methodology was required to reflect the operations and structure of the amalgamated Company.

II. Background and purpose

As of 1 January, 2019, Enbridge amalgamated Union Gas and Enbridge Gas to form EGI. As rate-regulated entities, EGD and UGL filed a joint application to the Ontario Energy Board (OEB) for approval to amalgamate the entities to form one entity — EGI. As part of the application, the submission detailed that there would be an alignment of accounting policies to combine the two entities for purposes of financial reporting in accordance with US GAAP.

Prior to the amalgamation, EGD and UGL capitalized indirect overhead using their respective legacy methodologies that, as asserted by management, conformed with US GAAP and that were also previously (and separately) approved by the OEB. After the amalgamation, EGI pursued a harmonized capitalization methodology due to the need for more a streamlined and efficient approach to capitalize overhead and incorporating industry best practices that have developed since the time of legacy approaches. Further, the new methodology is inspired by the need for unified accounting policies and meeting the regulatory requirement of ensuring that capitalization rates actually reflect the capital work within the newly amalgamated entity.

As part of our engagement, EY assisted management in the documentation of a harmonized policy, provided accounting and financial reporting assistance in connection with EGI's review of overhead capitalization rates and provided observations to management as a result of our procedures performed.

This report has been prepared for Enbridge Gas Inc.

III. Methodology and rates

Application of indirect overhead

Overhead costs that can be linked to the creation of capital are expenses that support the production or construction of an asset, but cannot be directly associated with any particular asset or working group. In general, the types of overhead costs that the Company has historically capitalized are as follows:

Specific capital support: This category encompasses processes for evaluating, designing and implementing specific capital projects. This would been seen in a situation where a project has been approved but the costs for this activity are not charged directly to capital as a specific project cannot be identified. A practical example at EGI is when a manager or director is involved in supporting multiple projects and cannot track time to specific projects due to the volume of projects.

Support and oversight of activities: This category encompasses processes for the supervision and administration of those activities that are charged directly to capital projects. Functions that support, supervise and monitor these direct capital project activities will have an appropriate portion of their costs allocated to indirect capital overhead.

Support functions: A function can be defined as a group of employees that collectively perform a particular function or role. This category includes the support functions that enable the various departments that perform the capital function to do their work. These support functions include: budgeting/reporting, building maintenance, IT help desk, human resources, legal, regulatory, strategic development, procurement, plant accounting and accounts payable.

The basic premise behind the allocation of overhead costs is that it is linked to the root cause of the capital activity, reflects the actual capital activity and is indicative of the operations of the business. The Company intends to apply a model that will ensure the consideration of two key areas:

- Consideration of geographical regions
- Causality of the overhead cost with respect to capital activity

In the proposed harmonized framework, the Company intends to implement three different cost drivers based on the nature and function of the business unit to ensure that costs are being capitalized based on the most relevant driver.

Capital spend (geographical considerations) for operations costs:
Through the amalgamation, EGI will service a larger geographical area than the previous legacy companies. As such, management has determined that the level of capital activity within geographical regions may differ, and therefore the capitalization rate of business groups that directly support these regional groups (and are not centralized) should reflect the respective region. For example, capital activity will likely be greater in a region experiencing higher development growth. On the contrary, Operations & Maintenance ("O&M") activity may be greater in a region where housing developments have already peaked. As a result, the overhead costs relating to operations groups will be capitalized using a ratio of direct internal capital expenses to the total of all non-overhead costs for each region. As determined by the Company, there are seven regions: Toronto, GTA East, GTA West/Niagara, Eastern, Northern, Southwest and Southeast.

The formula for the calculation of the indirect overhead capitalization rate below. Using this formula, EGI will be able to update the operations costs capitalization rates for indirect overhead on an annual basis in order to ensure that the capitalization rate closely reflects the capital activity of the Company.

[Direct Labour + Direct Materials] / [Total Direct Capital Costs + Total Direct O&M Costs – Outside Services and Contractor Costs]

Direct labour and direct materials comprise of internal costs, and do not include outside services and contractor costs as a part of this calculation. Once the unique rate is calculated for each region, it will be applied to the total pool of O&M costs for each respective region to determine the indirect overhead allocation.

Time analysis for business costs:
Certain areas of the Company support the operations of the business, but are not necessarily directly involved in capital projects. For these groups to better understand and accurately depict their capital involvement, time analysis has been determined to be the best indicator of capital activity. Time analysis is an estimate that is developed by the managers of each individual department through the completion of templates, which incorporate the allocation of each individual employees' time within that department between the various activities and responsibilities of the respective group. Based on the appropriate accounting guidance as defined in ASC 360-10, and enterprise capitalization policies, these activities are grouped between Capital and O&M, as appropriate. A weighted average of Capital to O&M time is calculated between all employees in that manager group. This average is then applied to all costs incurred within a specified director group based on the completed templates and capitalized at that respective rate.

In some situations, where labour hours data was not available or reflective of the group's activities, the capitalization rate was determined by the company through calculating the proportion of indirect capital spend compared to the gross costs of the group.

Using the time analysis templates, EGI will be able to update the business costs capitalization rates for indirect overhead on an annual basis in order to ensure that the capitalization rate closely reflects the capital activity of the Company.

Shared services costs:
Certain areas of the Company that support all activities of the business will be grouped as part of a shared services pool. Costs from these groups will not be capitalized using the time analysis or capital spend approach. Due to the nature of these groups, expenses are tracked at an aggregate level, but support the capital operations of the business. For example, HR would play an integral role in the developing of job postings, determining roles and responsibilities and ultimately hiring individuals whose function would be to complete capital projects. As a result, a single capitalization rate has been computed for this pool taking into the account the average capital activity of the areas of the business that are supported by the shared services group.

Using the weighted average methodology, EGI will be able to update the shared service costs capitalization rates for indirect overhead on an annual basis in order to ensure that the capitalization rate closely reflects the capital activity of the Company.

Human Resources (Direct and Indirect Loadings):
Under EGI’s capitalization methodology, HR pension and benefits associated to employees charging time directly to capital projects (i.e. HR pension and benefits related to direct labour costs), will be capitalized directly to projects. This is referred to as direct loadings.

HR pension and benefits associated with employees not charging time directly to capital projects (i.e. HR pension and benefits related indirect labour costs), is referred to as indirect loadings. For indirect labour costs that are capitalized, a rate will be applied to the salaries and wages capitalized to allocate the appropriate amount of HR pension and benefit costs to capital.

The remaining costs of the HR group (i.e. non-pension and benefits costs), which cannot be allocated based on either the direct loadings or indirect loadings methodology will be allocated through the shared services allocation method discussed above.

Corporate Allocations:
Corporate allocations are comprised of charges that reflect EGI’s net share of the costs incurred by other subsidiaries or corporate to support EGI. These costs are composed primarily of two categories: shared services and human resources.

The first category of cost allocations are similar in nature to shared services costs. They are centralized functions carried out by another lines of businesses or Enbridge Inc. that support EGI. As a result, when these centralized functions costs are allocated down to EGI, they are capitalized at EGI using the shared services rate discussed above. This is because the costs allocated to EGI were incurred to support the overall EGI business, and are no different in principle from a shared service cost incurred at EGI.

The second category of cost allocations are related to the HR function (i.e. pension and benefits and HR department costs) that support EGI. These HR cost allocations are capitalized at EGI using a weighted average HR rate reflects the nature of costs being allocated down to EGI. The HR rate is comprised of pension and benefits (i.e. direct loadings and indirect loadings) and HR department costs (i.e. capitalization of HR department costs via shared services method).

IV. Final summary of costs and rates

Presented below is a summary of EGI's 2020 indirect overhead capitalization based on the harmonized capitalization methodology being adopted. All amounts are based on 2020 budgeted figures.

Cost Category	Amount
Operations	$93,465,509
Business Costs	$47,439,612
Human Resources	$61,386,770
Shared Services	$21,656,247
CAM Costs	$29,352,208
Total	$253,300,346

For a summary of capitalization rates calculated under the harmonized capitalization methodology, please see Appendix II.

V. Procedures taken by EY in providing management assistance

As part of EY's assistance to management in determining the new overhead capitalization methodology, several steps were taken to document the overhead rates used for various functions:

1. Obtained an understanding of the overhead capitalization practices at the legacy companies;

2. Documented all cost centres and calculated the overhead percentage for each one based on raw data provided by the Company. EY further segmented the cost centres into the various departments within the organization;

3. Interviewed with key personnel for the selected sample functions: EY interviewed several managers and directors from various functions who were responsible for completing the capitalization template for their respective group. Through this interview process, EY obtained the following information:

    a. The role and responsibility of each individual within the department/function. This included examples of day-to-day responsibilities as well as ad-hoc tasks that would be expected from each individual within the functional unit. Please refer to the discussion below on cost drivers;
    b. An understanding of the basis used to determine the amount of time each individual spends on capital-related tasks and document the linkage to causality. Please refer to the discussion below on cost causation linkage.
    c. Any additional costs that are incurred within the department outside of labour-related costs and whether those costs should or should not be capitalized on the same basis as labour;
    d. An understanding of the project life cycle, including when a project is considered to be a capital activity in relation to the life cycle; and
    e. An understanding of any considerations made by management with regards to the hierarchy of individuals within a department when evaluating the amount of time they spend relating to capital projects. Please refer to the discussion below on cost causation linkage;

4. Assisted management by providing alternative and best practices within industry;

5. Worked collaboratively with the Company to assist in documenting an updated framework for indirect overhead capitalization for the amalgamated Company;

6. Documented US GAAP and other technical guidance as issued by the OEB;

7. Detailed observation of all significant director groups to understand the cost drivers in legacy environment in order to work with management to determine cost drivers for future state capitalization methodology;

8. Understood the policies and procedures relating to the capitalization of indirect overhead at Enbridge Inc. These policies can be found in Appendix I;

9. Obtained an understanding of the cost causation linkage. Further documentation has been included below; and

10. Examined Capital vs O&M considerations: EY worked with management to categorize activities into capital and O&M. EY relied on the following OEB and US GAAP guidance below and the EGI Capitalization Policy (See Appendix I).

VI. Accounting guidance

Whilst this list is not comprehensive in nature, as part of our study, the following guidance was considered:

<u>"Ontario Energy Board: Uniform system of accounts for Class A gas utilities – Appendix A"</u>

"Overhead Charged to Construction: includes engineering, supervision, administrative salaries and expenses, construction engineering and supervision, legal expenses, taxes and other similar items. The assignment of overhead costs to particular jobs or units shall be on the basis of a reasonable allocation of actual costs. The records supporting the entries for overhead charged to construction costs shall be maintained so as to show the total amount for each element of overhead for the year and the basis of allocation."

<u>US GAAP</u>

ASC 360–10: *"Property, plant and equipment should be recorded at historical cost, which includes the costs incurred for activities to bring them to the condition and location necessary for their intended use. Interest costs incurred during the period the assets are brought to that condition and location are also included in the historical cost of acquiring the asset, if material."*

ASC 980-340: *"25-1 Rate actions of a regulator can provide reasonable assurance of the existence of an asset. An entity shall capitalize all or part of an incurred cost that would otherwise be charged to expense if both of the following criteria are met:*

a. It is probable (as defined in Topic 450) that future revenue in an amount at least equal to the capitalized cost will result from inclusion of that cost in allowable costs for rate-making purposes.

b. Based on available evidence, the future revenue will be provided to permit recovery of the previously incurred cost rather than to provide for expected levels of similar future costs. If the revenue will be provided through an automatic rate-adjustment clause, this criterion requires that the regulator's intent clearly be to permit recovery of the previously incurred cost.

A cost that does not meet these asset recognition criteria at the date the cost is incurred shall be recognized as a regulatory asset when it does meet those criteria at a later date."

Based on the accounting guidance above, the OEB allows for the capitalization of overhead. Further, US GAAP calls for the capitalization of all costs *incurred for activities to bring assets to the condition and location necessary for their intended use*. The guidance as per the regulatory standard (ASC 980) further allows for any costs to be included as long as future recovery through rate base is probable.

VII. Cost causality

Cost causality is the relationship between the cost incurred and capital activity. For clarity, it would be expected that a cost driver used by management would be the most appropriate to determine the linkage with capital activity.

As part of assisting management in documenting an updated cost capitalization framework, EY observed the various mechanisms management intends to use to capitalize indirect overhead. EY conducted several interviews with various areas of the business to better understand cost causality.

Capital spend (geographical regions) – As noted earlier, the seven operational regions within EGI will capitalize overhead based on a direct capital spend ratio. This ratio has been determined by management to be the best indicator of cost causality for the indirect overhead costs relating to operations, as it represents the actual allocation of labour and materials resources by the Company to capital versus O&M projects. As a result, management asserts that the operations support groups who indirectly support the direct projects allocate their resources based on the same breakdown of capital versus O&M. Through discussion with management and observations based on our understanding of the business and other industry participants, this approach is a consistent way to allocate overhead costs for support services closely linked to active projects.

Time analysis (labour) – Several director groups across the Company will be capitalizing overhead based on a time analysis completed by their respective manager groups. These groups will use a labour cost driver (otherwise referred to as a time analysis) as the basis of determining the percentage of time an individual spends on capital activity. Management has determined that labour hours are the most appropriate cost driver in these situations as the time spent on performing capital work would be most reflective of the amount of effort involved in relation to capital activity. Through our understanding of best practices and interviews held with divisional managers, EY observed that the templates completed by the respective groups are segmented by the nature of the activity performed, which can then further be aligned to capital and O&M activities. EY observed that the hierarchy of an individual has been incorporated in the assessment of the individual departments and functional units. Therefore, an individual who is of a more senior rank would have a lower capitalization rate than an individual who is closer to the capital activity.

Shared service rates – Shared services are administrative groups within the Company (or at an EI level) that inherently support all capital and O&M projects in various ways. The determination of an overhead rate for these groups is determined based on the capital activity associated with the seven operational regions of the Company as well as indirect overhead for business costs allocated at the director level, supported by the shared services groups. As a result, based on a review of industry best practices and the fact that shared services support the Company as a whole, management asserts that a weighted average rate for administrative groups is the most appropriate method.

Burdening (HR Benefits) – One of the most evident forms of cost causality can be noted within human resources benefits. When an employee spends an hour working on a capital project, then that portion of that employee’s pension and benefits costs are incurred as a result of that capital project. At EGI, this is the case as overhead costs incurred via the cost of employee benefits are caused by the fact that the employees, whether direct or indirect labour, are working to support various projects within EGI. Therefore, management has determined that a loadings rate will be used in order to charge the capital of HR benefits to capital projects that the employees are working on.

VIII. Industry best practices

As part of the overhead capitalization study, EY reviewed best practices through our understanding and discussions with peers in the industry. Several areas of importance were identified and have been listed below:

Direct to capital – One of the primary areas of focus involves the importance of tracking actual costs to projects. Rather than applying an estimated overhead rate, being able to directly charge to a capital project eliminates the estimation and provides the most accurate and reliable information. As companies continue to find ways to increase direct costing, this continues to be a leading practice. Management's proposed framework has introduced loadings for all employees who are currently charging direct to capital, and also indirect loadings in order to burden the costs of employees who are indirectly supporting capital projects.

Project life cycle considerations – The life cycle of a project generally dictates when costs can be capitalized to a project. Due to the fact that this can be somewhat ambiguous, it is generally best practice to start capitalization once management approval is granted for a project, after the completion of surveys/studies required to determine project viability. Through our discussions and observations, this is a benchmark followed by EGI in its capitalization policies and methodologies.

Regional and geographical considerations – Due to the amalgamation, EGI now operates over a much larger geographical area than the legacy companies. Through our observation and understanding, other industry participants have factored in the geographical area of certain functions within their business. For the purposes of clarity, if a function operates in multiple geographical areas, the overhead rate for each geographic area (albeit for the same function) may be different based in the nature of the capital activity in that function. Similarly, the proposed EGI model will incorporate geographical and regional considerations for certain operations groups in the determination of their overhead rate.

Documenting capital activity – In order to support the indirect capitalization rates, specifically in areas where the cost driver has been determined to be labour, industry participants document and annually review the calculation of such rates. Through EGI's proposed model, the Company will join these industry participants by annually providing a template to the different business functions to link the labour-based capitalization rates to reflect the capital activity within those functions.

Allocation of indirect overhead based on capital dollars spend – An area of alternate practice amongst other companies is the determination of the cost driver. In certain instances, the capital spend of a group would better reflect the capital activity within the group rather than labour hours or another alternative measure. Through our understanding and discussions with management, EY has observed that the capital activity of departments within the operational groups is allocated based on their capital spend ratio.

When determining the overhead rate for regional operational groups, EGI allocates using the capital spend ratio. However, when determining director-level rates for business costs, EGI allocates indirect overhead based on a time analysis completed by employees, as in management's view this allows for a more accurate rate.

Annual or bi-annual road shows – There is a growing trend in the industry to have road shows run by internal leadership to focus on key finance issues. Given the amalgamation and proposed changes in the capitalization framework, management may find it useful to communicate capitalization rate and method updated throughout the business using this approach.

IX. Findings and observations

The harmonized capitalization methodology that will be used by EGI includes an assessment of cost driver analysis and basis for allocation via management's completion of the templates, and the related causality to capital projects. Based on our observations, the application of this harmonized model considers the applicable accounting framework and the enterprise wide capitalization policy. In addition, interviews conducted with managers and staff provide management with an understanding of capital activity, to allow for an allocation based on an expected time analysis.

Appendix I – EGI Capitalization policy

EGI Enterprise Wide
Capitalization Policy.p

Appendix II – Summary of EGI Capitalization Rates

Director Group	Sub-category	Actuals Cap Rate
Marketing & Energy Conservation	N/A	0.0%
Customer Care Development	N/A	0.0%
Customer Care Operations	N/A	0.0%
Large Volume Contracting & Policy	N/A	0.0%
VP Admin Customer Care	N/A	0.0%
Energy Services - Director	N/A	0.0%
Gas Control & Management	N/A	0.0%
Gas Supply.	N/A	0.0%
S&T Joint Ventures	N/A	0.0%
VP Admin-Energy Services	N/A	0.0%
VP Admin Operations	VP Admin Operations - Synergy	0.0%
Business Development & Regulatory (excluding Market Development & Energy Conservation)	Business Development	0.0%
Business Development & Regulatory (excluding Market Development & Energy Conservation)	Regulatory Affairs	19.8%
Business Development & Regulatory (excluding Market Development & Energy Conservation)	Public Affairs & Ombudsmen	4.8%
Business Development & Regulatory (excluding Market Development & Energy Conservation)	VP Admin Bus Development	9.7%
Major Projects	N/A	100.0%
Distribution in Franchise Sales	N/A	8.3%
S&T Business Development	N/A	6.3%
Asset Management Director	N/A	57.0%
Engineering	N/A	50.8%
Integrity & IMS	Integrity	21.0%
Integrity & IMS	Integrity - Inline Inspection	0.0%
System Improvement	N/A	53.5%

Director Group	Sub-category	Actuals Cap Rate
VP Admin Engineering & Asset Management	N/A	53.1%
IMO	N/A	27.5%
Storage Operations.	Storage Operations	4.5%
Storage Operations.	Storage Operations - Excluded	0.0%
Trans & Compression - Engineering & Execution	Trans & Compression Engineering & Execution - Included	25.3%
Trans & Compression - Engineering & Execution	Trans & Compression Engineering & Execution - Excluded	0.0%
Trans & Compression Operations	N/A	4.5%
VP Admin – STO & IM	N/A	9.9%
Warehouse - SCM	N/A	100.0%
Human Resources	Pension and benefits	N/A
Human Resources	Non-Pension and benefits	19.5%
Human Resources	LUG Direct Loadings	N/A
Eastern Region Operations	Eastern Region Ops.	66.0%
Eastern Region Operations	Eastern Region Ops. - Direct O&M	0.0%
GTA East Operations	GTA East Ops.	54.7%
GTA East Operations	GTA East Ops. - Direct O&M	0.0%
GTA West/Niagara Operations	GTA West/Niagara Ops	60.4%

Director Group	Sub-category	Actuals Cap Rate
GTA West/Niagara Operations	GTA West/Niagara Ops - Direct O&M	0.0%
Northern Region Operations	Northern Region Ops	44.4%
Northern Region Operations	Northern Region Ops - Direct O&M	0.0%
Operations Support	Operations Support	49.5%
Operations Support	Operations Support - Customer Attachments	100.0%
Operations Support	Operations Support - Distribution Protection - Locates & Leak Survey	0.0%
Southeast Region Operations	Southeast Region Ops	45.2%
Southeast Region Operations	Southeast Region Ops - Direct O&M	0.0%
Southwest Region Operations	Southwest Region Ops	40.4%
Southwest Region Operations	Southwest Region Ops - Direct O&M	0.0%
Toronto Region Operations	Toronto Region Ops	70.0%
Toronto Region Operations	Toronto Region Ops - Direct O&M	0.0%
VP Admin Ops	VP Admin Ops	44.1%
EHS	N/A	19.5%
Accounting	N/A	19.5%
Business Partners	N/A	19.5%
Finance Admin	N/A	19.5%
FP&A	N/A	19.5%

Director Group	Sub-category	Actuals Cap Rate
Utility Finance Alignment	N/A	19.5%
Facilities & Workplace Services	N/A	19.5%
Supply Chain Other	N/A	19.5%

Below is a listing of Cost Centres that do not have a Director Group affiliated to them. As a result, rates are presented by Cost Centre as opposed to Director Group. These cost centres belong to shared services and O&M groups.

Cost Centre	Actuals Cap Rate
CC25263-COST TO ACHIEVE (GL)	0.0%
CC10899-Auditfees	19.5%
CC25206-AUDIT SERVICES	19.5%
CC25257-LANDS (PROJECT ACCOUNTING)	19.5%
CC25000-EXECUTIVE	19.5%
CC25228-IT GD GRAPHIC COMMUNICATION SERVICES	19.5%
CC25233-IT ISS END USER SERVICE	19.5%
CC25234-IT ISS CORE INFRASTRUCTURE	19.5%
CC25280-IT GD ADMINISTRATION	19.5%
CC25281-IT GD Data & Support Services	19.5%
CC25282-IT ES EFS	19.5%
CC25284-IT ISS Network Services	19.5%
CC25286-IT GD TECHNOLOGY PLANNING	19.5%
CC25287-IT GD BA & OAM	19.5%
CC25291-IT GD BA Capital	19.5%
CC25293-IT GD Productivity Services	19.5%
CC10990	19.5%
CC25002-LAW DEPARTMENT	19.5%
CC25005	19.5%
CC25007-CORPORATE SECRETARY	19.5%
CC25009-ETHICS & COMPLIANCE	19.5%
CC25205-RISK MANAGEMENT	19.5%
CC25207-TAX	19.5%
CC25246 - PAC EXTERNAL AFFAIRS CAN	19.5%
CCUN_21150-Energy Services - IMO CTA	0.0%
CCUN_21151-Operations -IMO CTA	0.0%
CCUN_21152-Engineering & Asset Management - IMO CTA	0.0%
CCUN_21153-Customer Care - IMO CTA	0.0%
CCUN_21154-Business Development & Regulatory -IMP CTA	0.0%
CCUN_21155-Storage Transmission & IMO - IMO CTA	0.0%
CCUN_20798-O&M Affiliate Revenue : Corporate	19.5%
CCUN_22738-CTL:OM	19.5%

Cost Centre	Actuals Cap Rate
CCUN_22758-CTL:OH	19.5%
CCUN_22789-AUDIT:OM	19.5%
CCUN_22106-DEGT - Env Health & Safety - OM	19.5%
CCUN_22124-Environment	19.5%
CCUN_22196-DEGT - Env Health & Safety S&R - OM	19.5%
CCUN_20398-FI:Credit OM	19.5%
CCUN_20399-FI:Credit OH	19.5%
CCUN_20410-Senior Mgmt - President	19.5%
CCUN_20480-Senior Mgmt - Overhead Capitalized	19.5%
CCUN_22150-IT Enterprise Projects OH	19.5%
CCUN_22701-IT:OM	19.5%
CCUN_22739-IT:OH	19.5%
CCUN_22763-DCAN:IM:OM	19.5%
CCUN_22765-IM:OH	19.5%
CCUN_22776-ITI:OM	19.5%
CCUN_22777-ITI:OH	19.5%
CCUN_22791-IT Enterprise Projects O&M	19.5%
CCUN_22792-SE:ITI:OM	19.5%
CCUN_22793-SE:ITI:OH	19.5%
CCUN_22811-Gas Supply - Tech Support	19.5%
CCUN_22821-Gas Supply - Tech Support	19.5%
CCUN_23776-ITI Client Services OM	19.5%
CCUN_23777-ITI Client Services OH	19.5%
CCUN_24776-ITI Core Infrastructure OM	19.5%
CCUN_24777-ITI Core Infrastructure OH	19.5%
CCUN_22512-Insurance Services - OM	19.5%
CCUN_22513-Insurance Services - OH	19.5%
CCUN_22510-Legal Services - OM	19.5%
CCUN_22511-Legal Services - OH	19.5%
CCUN_20684-AP - Capitalization	19.5%
CCUN_22324-A/P - Administration - Admin	19.5%
CCUN_20303-FBS - Taxation - Admin	19.5%
CCUN_20713-Government & Indigenous Affairs - OH	19.5%
CCUN_22938-MCC VP,SS O&M cost centre	19.5%
CCUN_22948-Government Relations	19.5%
CCUN_22951-Government Affairs	19.5%

BURDEN RATES
DWAYNE CONROD, HR DIRECTOR

1. The purpose of this evidence is to describe the methodology used to calculate employee burden rates. Burden rates are used to establish the fully allocated cost for employee labour used to estimate project costs. Enbridge Gas's Human Resources function reviews and prepares burden rates annually. These burden rates are used in the determination of overhead capitalization. Details on overhead capitalization are provided at Exhibit 2, Tab 4, Schedule 2.

2. This evidence is organized as follows:
    1. Burden Rates
    2. Incentive Pay
    3. Benefits
    4. Pension
    5. Variances in Burden Rates
    6. Burden Rate Results
    7. Capitalization

1. Burden Rates

3. Burden rates are calculated based on the cost for maintaining an employee above and beyond the employee's associated base salary (fixed compensation). Burden rates are for employees only. Contractors are excluded as they do not receive incentive pay or participate in the pension and benefits programs. Burden rates are comprised of incentive pay (short and long-term), pension, company-provided benefits (i.e. extended health and dental coverage), employee savings plan, and legislative benefits (i.e., Canada Pension Plan (CPP), Employment Insurance (EI), etc.). Burden rates vary by role category and organization level. Role categories are identifiers (Clerical, Technical, Professional, Manager) used to group like jobs

together.

4. Enbridge Gas uses an average burden rate to support project cost modelling including the capitalization of costs for self-constructed assets. The methodology to determine burden rates for each organization level is as follows:
   a) An average burden rate is determined for each component (incentive pay, pension and benefits) by organization level; and
   b) The combined average burden rate by organization level is calculated by adding each of the components together (incentive pay, benefits and pension).

   The following sections provide further detail on each of the components (incentive pay, benefits and pension) included in burden rates.

2. Incentive pay

5. Enbridge Gas's burden rate includes a component for incentive pay. Incentive pay includes the target level for both the Short-Term Incentive Plan (STIP) and the Long-Term Incentive Plan (LTIP). All roles at all organization levels are eligible to receive STIP, while only roles at the manager level and above are eligible for LTIP. STIP and LTIP targets are defined as a percentage of annual base pay and vary by organization level. Prior to the merger between Enbridge Inc. and Spectra Energy Corp., the burden rate methodology differed between EGD and Union. The burden rates calculated by Union excluded LTIP.

3. Benefits

6. The burden rates for the employee benefits component reflect costs for active employee benefits, including medical and dental coverage, flex credits (company-paid credits to purchase or enhance benefits), long-term disability (LTD) premiums,

CPP premiums, EI premiums, Workers' Safety and Insurance Benefits and Employer Health Tax, as applicable. The benefits burden rate is determined as:

Benefits burden rate	=	Average expected annual per-employee cost	÷	Average base pay for each organization level

The methodology to determine these components is as follows:

a) With the assistance of Willis Towers Watson (WTW), a benefits consultant, the expected annual employee cost for each benefit is determined based on the most recent program costs adjusted for expected changes that can be reasonably estimated to occur in the next year. WTW assists with identifying and measuring the impact of expected changes in benefits costs which could include inflationary drivers and approved changes in the program design. Expected costs are determined separately by components that differ by pay (e.g., flex credits, LTD premiums, CPP premiums) and those that are fixed (e.g., medical, and dental coverage);
b) The average base pay for each organization level is measured based on current payroll data; and
c) The benefits burden rate is equal to the value determined under a, divided by the value determined under b.

7. Prior to amalgamation, EGD and Union applied a similar methodology for determining the burden rate for employee benefits and no changes have occurred.

4. Pension

8. The burden rates for pension includes a defined benefit pension plan provision and a defined contribution pension plan provision. These are described separately below.

9. The burden rates for the defined benefit pension plans are derived from actuarial assumptions and actuarial methodologies. These actuarial assumptions and methodologies are determined by Mercer (Canada) Limited (Mercer), an actuarial consulting firm, to reflect that pension benefits are accrued during active employment, but not paid until retirement or termination. Actuarial assumptions are determined based on the assumptions used for financial reporting purposes, as disclosed in the Company's audited financial statements provided at Exhibit 1, Tab 8, Schedule 1, Attachments 1 and 2. One exception is the discount rate used to determine burden rates. The discount rate is based on the 5-year average discount rate used for financial reporting purposes. A 5-year average is used to smooth short-term fluctuations arising from using a single point-in-time estimate.

10. The annual current service cost is determined in accordance with generally accepted actuarial methods established by the Canadian Institute of Actuaries. A description of the method follows:
    a) Current service cost is estimated using the Projected Unit Credit method - a generally accepted and commonly used benefit attribution method established under actuarial principles;
    b) Under this method, each employee's benefits under the plan are attributed to years of service, taking into consideration future expected salary increases and the plan's benefit allocation formula. Thus, the estimated total pension to which each employee is expected to become entitled at retirement is broken down into units, each associated with a year of past or future credited service;
    c) An employee's estimated current service cost is the present value of the benefit attributed to the year of service in the plan year;

d) The current service cost reflects the company-paid portion of the pension plan only and so excludes required employee pension contributions; and
e) The final step is to estimate the average annual current service cost over a career for each individual in a hypothetical employee population, divided by the projected pay over the same career period.

11. The burden rates for the defined contribution plans reflect the employer contribution as a percentage of base pay for each organization level.

12. Finally, the combined pension burden rate is determined as a blend of the defined benefit and defined contribution pension plan burden rates, based on the population participating in each plan.

13. Prior to amalgamation, pension burden rates derived for both EGD and Union were determined based on similar methodologies and assumption-setting processes, with one exception: the Union pension burden rates were measured using the most recent accounting discount rate disclosed in the financial statements, not a 5-year average.

5. Variances in Burden Rates

14. Burden rates can differ from year to year due to:
a) Changes to the program design;
b) Changes in assumptions and methodology; and/or
c) Changes in the costs of the programs.

15. Every three to five years Enbridge Gas reviews (and periodically revises) the incentive pay, benefit, and pension programs to align with competitive industry practice, optimize total program value or adjust costs. These changes can impact

the burden rates. As well, assumptions impact burden rates and can change each year. The assumptions applied to each component of the burden rates are determined based on the market environments, industry best practice and reasonable expectations at the time the rates are calculated. Finally, the costs and burden rates for some programs will change for reasons outside of the Company's control. Examples of changes in the costs of the programs are:

a) Medical or LTD premiums are established by plan experience and the insurance company and may change premiums despite there being no change in the underlying coverage; and
b) Costs for legislative benefits are established by provincial and Federal agencies and authorities and can change these costs from time to time.

6. Burden Rate Results

16. The average burden rate is the sum of the burden rates determined for each of the compensation components, as described above (incentive pay, benefits and pension).

Average burden rate % for each organization level	=	Incentive pay burden %	+	Benefits burden %	+	Pension burden %

17. Table 1 summarizes the average burden rates by organization level from 2019 to 2022 for Enbridge Gas for roles up to and including the Manager level. Roles above the manager level are not included as they are not typically included in the project capitalization process.

Table 1
Enbridge Gas Burden Rates by Organization Level

Line No.	Particulars	Utility	2019	2020	2021	2022(2)
			(a)	(b)	(c)	(d)
	Organization Level					
1	E300 – Clerical	EGI	43.7%	N/A (1)	N/A (1)	N/A (1)
2	E310 – Clerical	EGI	42.9%	43.0%	42.6%	42.4%
3	E320 – Clerical / Technical	EGI	44.8%	45.8%	44.6%	45.1%
4	E400 – Technical / Professional	EGI	43.9%	44.2%	43.1%	43.4%
5	E410 – Technical / Professional	EGI	42.5%	42.8%	41.6%	41.9%
6	E420 – Technical / Professional	EGI	41.2%	41.5%	40.2%	40.5%
7	E500 – Specialist	EGI	45.2%	45.4%	44.0%	44.2%
8	E510 – Specialist	EGI	44.3%	44.4%	42.9%	43.1%
9	E600 – Manager	EGI	63.0%	63.1%	61.5%	61.5%
10	Unionized Staff	EGI	38.2%	38.0%	37.8%	38.1%

Notes:
(1) No data shown due to no roles administered in this grade
(2) 2022 rates are used to determine the 2023 Bridge Year burden rate and the 2024 Test Year burden rate provided at Exhibit 2, Tab 4, Schedule 2, Table 1

18. EGD historically did not use burden rates for the capitalization of overhead, rather capitalization rates were used. Consequently, 2013 OEB-approved burden rates cannot be provided for EGD. Exhibit 2, Tab 4, Schedule 2 provides detail on EGD's historical overhead capitalization methodology.

19. Table 2 provides the burden rates used to determine 2013 rates for Union Gas.

Table 2
Historical Burden Rates by Organization Level – Union Gas

Line No.	Particulars	Utility	2013
			(a)
	Organization Level		
1	Clerical	Union	45.20%
2	Technical	Union	45.20%
3	Hourly	Union	45.60%
4	Management	Union	52.40%

7. Capitalization

20. Exhibit 2, Tab 4, Schedule 2 provides details on Enbridge Gas's harmonized overhead capitalization methodology. The harmonized methodology utilizes the burden rates set out in this Exhibit.

CAPITAL EXPENDITURE OVERVIEW

DANIELLE DREVENY, MANAGER CAPITAL FINANCIAL PLANNING & ANALYSIS
BOB WELLINGTON, MANAGER ASSET MANAGEMENT GOVERNANCE AND RISK

1. The purpose of this evidence is to provide an overview of Enbridge Gas's capital expenditures. Details regarding capital expenditures are provided at Exhibit 2, Tab 5, Schedule 2 and Exhibit 2, Tab 5, Schedule 3.

2. This evidence is organized as follows:
    1. Introduction
    2. Capital Expenditure Overview
    3. Summary

1. Introduction

3. The evidence set out in Exhibit 2, Tab 5 focuses on the capital expenditures for Enbridge Gas and addresses the requirements in Section 2.2.5 of the Filing Requirements for Natural Gas Rate Applications[1]. The 2024 Test Year forecasted capital expenditures are provided at Exhibit 2, Tab 5, Schedule 2. A summary of utility capital expenditures for the period 2013 to 2018 and detailed variance analysis for the period of 2019 to 2024 is provided at Exhibit 2, Tab 5, Schedule 3.

4. Prior to amalgamation, EGD and Union operated under separate Incentive Rate-Setting (IR) mechanisms and prioritized investments according to their respective capital planning processes. EGD operated under a Custom IR framework[2] which included an OEB-approved level of capital expenditure for the 2013 Test Year and a 5-year forecast of capital expenditure from 2014 to 2018. In contrast, Union

[1] Filing Requirements For Natural Gas Rate Applications, February 16, 2017.
[2] EB-2012-0459.

operated under a Price Cap IR[3] mechanism which included an OEB-approved level of capital expenditure for the 2013 Test Year with rates escalated for the IR term of 2014 to 2018. Any significant projects outside of OEB-approved capital expenditures for Union were subject to approval through the OEB Capital Pass Through (CPT) mechanism.

5. In 2018, EGD and Union received OEB-approval to amalgamate creating Enbridge Gas. In its decision approving the amalgamation, the OEB ordered that a 5-year deferred rebasing term, from 2019 to 2023, be applied to Enbridge Gas. During the deferred rebasing term, Enbridge Gas is operating with a Price Cap IR framework which includes the ability to apply for approval of significant projects not funded by rates under the Incremental Capital Module (ICM). ICM projects must meet specific criteria for need, materiality and prudence and be in excess of a materiality threshold which is calculated by rate zone on an annual basis. The materiality threshold is based on an OEB formula which determines the amount of capital being recovered in rates. Also included in the formula is an OEB mandated 10% deadband for spend before ICM funding can be accessed.

2. Capital Expenditure Overview

6. The Enbridge Gas capital expenditures budget addresses the requirements of approximately 3.8 million customers. These customers are served by 153,000 km of main and service pipelines for the distribution and transmission of natural gas, 36,146 stations and 311 petajoules (PJ) of underground storage facilities (199 PJ regulated and 112 PJ unregulated). Enbridge Gas assets provide the majority of Ontarians and Ontario businesses with safe and reliable natural gas, to meet annual gas demand of approximately 773 PJ and a design day demand of approximately 8 PJ.

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[3] EB-2013-0202.

7. Enbridge Gas has an established budget process which is underpinned by the Asset Management Plan (AMP). The AMP is provided at Exhibit 2, Tab 6, Schedule 2. The AMP Asset Management Framework is used to balance risk, cost and performance through the entire asset life cycle. Capital expenditures are prioritized based on the safety and reliability needs of the system and the timing of investments to replace and expand the natural gas system are prudently paced.

8. The level of capital expenditures for Enbridge Gas varies year-over-year largely due to significant replacement or reinforcement projects and the timing of the execution of those projects. Figure 1 shows capital expenditures over the 2013 to 2024 period.

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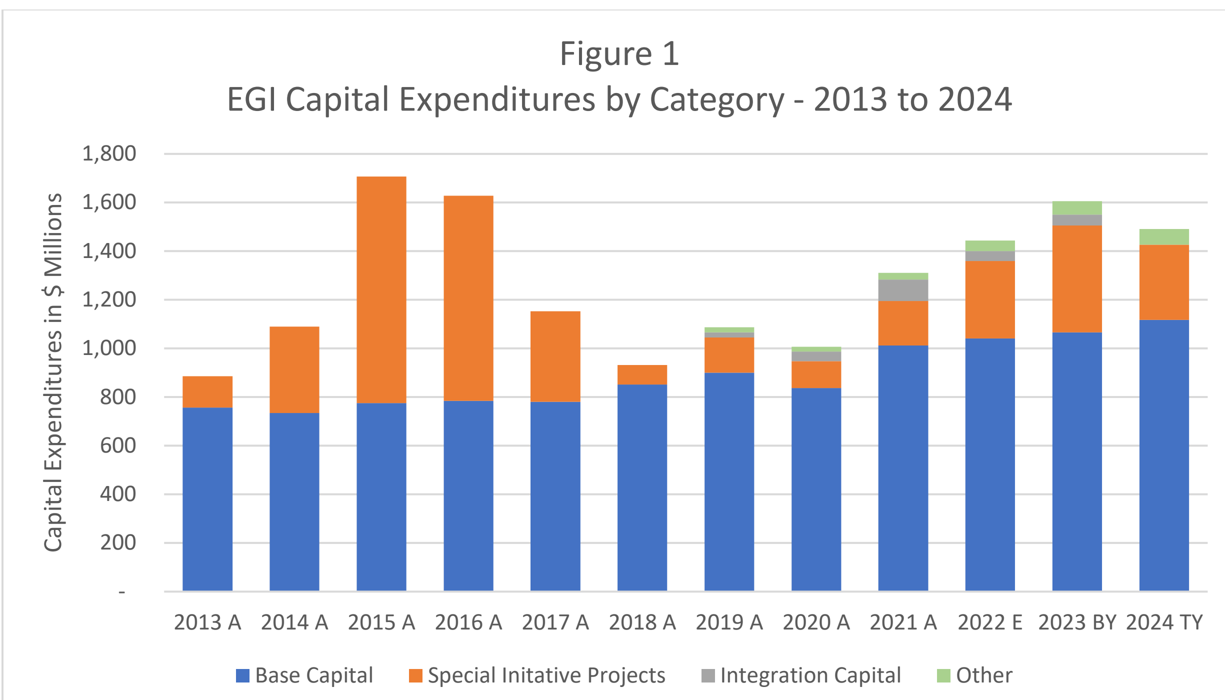

9. Base capital expenditures represent the ongoing capital requirements to maintain the safe and reliable operations of the Enbridge Gas system and to economically attach new customers. The base capital spend has been stable over both the 2013 to 2018 period for EGD and Union as well as the deferred rebasing term for Enbridge Gas. Base capital expenditures increased moderately for the 2020 to 2024 period due to several factors. The COVID-19 pandemic resulted in lower spend in 2020 due to work stoppages, labour and material shortages. The level of base capital expenditure increased in 2021 as COVID-19 restrictions lifted. Base capital expenditures have also increased over the 2021 to 2024 period due to investment needs identified for pipeline integrity and relocation projects, Gate, Feeder & A stations, meter exchanges and Technology & Information System projects to support evolving business needs. Enbridge Gas has not adjusted the 2022 to 2024 forecast to reflect the increases in inflation that have occurred since Q1 2022.

10. Special Projects include certain significant Leave to Construct (LTC) projects for EGD, investments approved under the Union's CPT mechanism, and projects approved for ICM treatment under Enbridge Gas's ICM mechanism. For the deferred rebasing term of 2019 to 2023, Enbridge Gas files annual rate applications with capital requirements supported by an AMP for the EGD and Union rate zones. Each year, Enbridge Gas has undertaken a prioritization process to arrive at a capital budget at or below that which is recovered in rates. This typically requires adjustments to the timing of projects in order to reduce planned spend. In years where it is not possible to reduce spend below the ICM Threshold, ICM projects are required. Projects must meet the ICM criteria of need, prudence and materiality in order to be included in the annual rate applications. The majority of ICM projects

are subject to LTC. Approval of an LTC application establishes need for a particular project.

11. Parties and the OEB had the opportunity to ask questions about any part of the Company's capital expenditures in years where an ICM request is made. With one exception[4], the OEB did not indicate issues with any specific capital projects in rate decisions during the deferred rebasing term.

12. Capital projects that supported the integration of EGD and Union were excluded from the respective AMP's and the revenue requirement for these projects was funded through synergy savings during the deferred rebasing term. Details on these synergies are provided at Exhibit 1, Tab 9, Schedule 1.

13. Other projects include Community Expansion and customer driven Compressed Natural Gas (CNG) and Renewable Natural Gas (RNG) projects.

14. The 2024 Test Year capital budget addresses Enbridge Gas's requirements to safely operate and maintain the natural gas system, respond to demand growth, invest in low-carbon solutions and ensure on-going reliability and service to rate payers. Similar to the planning processes applied for the 2019 to 2023 period, Enbridge Gas identified the investment requirements and needs and then rationalized the expenditures with a constraint.

15. Section 6.1.2 of the AMP, provided at Exhibit 2, Tab 6, Schedule 2, discusses the capital considerations for determining an appropriate constraint for the 2024 Test Year. Through consultation with internal stakeholders and in consideration of the

[4] EB-2018-0305, Decision and Order, September 12, 2019, p.19. The OEB determined that certain capital expenditures totaling $13 million were "premature".

asset class strategies, management of risk, ability to complete mandatory work, Customer Engagement Survey results and total in-service capital spend, a constraint of $1.2 billion with a 2% escalation factor was recommended. Enbridge Gas is not able to complete mandatory work or support the demand for growth at a constraint below $1.2 billion. The constraint of $1.2 billion is required to safely operate and maintain the natural gas system, respond to demand growth, invest in low-carbon solutions and ensure on-going reliability and service to customers.

3. Summary

16. Enbridge Gas has prioritized its capital expenditures over the 2013 to 2024 period in order to ensure the safety and reliability of the natural gas distribution system while supporting system growth. Enbridge Gas continues to follow established budget processes to prioritize capital expenditures and accommodate the majority of capital projects within approved base rates. The evidence provided at Exhibit 2, Tab 5, Schedule 2 further describes the prioritized spend for the 2024 Test Year. The evidence provided at Exhibit 2, Tab 5, Schedule 3 summarizes the historical capital expenditures for EGD and Union under their individual IR terms and details the year-over-year capital expenditure variances for Enbridge Gas during the deferred rebasing term.

CAPITAL EXPENDITURES

DANIELLE DREVENY, MANAGER CAPITAL FINANCIAL PLANNING & ANALYSIS
BOB WELLINGTON, MANAGER ASSET MANAGEMENT GOVERNANCE AND RISK

1. The purpose of this evidence is to present Enbridge Gas's 2024 Test Year capital expenditures. The capital expenditures in this evidence are comparable to the presentation in the Asset Management Plan (AMP) provided at Exhibit 2, Tab 6, Schedule 2. In-service capital additions are provided at Exhibit 2, Tab 2, Schedule 1.

2. This evidence is organized as follows:
    1. Introduction
    2. 2024 Test Year Capital Expenditures Forecast
    3. Summary

1. Introduction

3. This evidence focuses on the capital expenditures for the 2024 Test Year and also includes the five-year forecasted expenditures pursuant to Section 2.2.5 of the Filing Requirements For Natural Gas Rate Applications (Filing Requirements)[1]. Enbridge Gas is requesting approval for the 2024 Test Year capital expenditures; all other years are provided for informational purposes. Expenditures are shown on an annual basis. Adjustments are made to capital expenditures for multi-year projects in order to inform the 2024 Test Year capital additions as provided at Exhibit 2, Tab 2, Schedule 1. Multi-year projects (i.e. projects that are planned and executed over more than one year) are inclusive of Interest During Construction (IDC) costs as provided at Exhibit 2, Tab 4, Schedule 1. Table 1 summarizes

[1] Filing Requirements For Natural Gas Rate Applications, February 16, 2017.

annual capital expenditures by Asset Class, as shown in the Asset Management Plan (AMP). Categories of spend not included in the AMP include Community Expansion and Other which includes Renewable Natural Gas (RNG) and Compressed Natural Gas (CNG).

Table 1
Utility Capital Expenditures by Asset Class

Line No.	Particulars ($ millions)	Category	2024 Test Year	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	
			(a)	(b)	(c)	(d)	(e)	
1	Compression Stations	Storage	38.9	71.9	116.7	45.1	19.2	
2	Customer Connections	Growth	249.2	249.2	250.3	260.6	250.1	
3	Distribution Pipe	Dist Ops	368.3	333.3	268.7	292.3	316.4	
4	Distribution Stations	Dist Ops	120.6	109.8	111.4	106.5	116.3	
5	Fleet & Equipment	General	35.0	36.4	40.5	53.6	52.3	
6	Growth - Distribution System Reinforcement	Growth	105.1	173.0	40.8	8.3	10.3	
7	Real Estate & Workplace Services	General	56.6	75.6	103.5	54.6	56.4	
8	Technology Information Services	General	112.4	88.7	76.9	48.1	54.1	
9	Transmission Pipe and Underground Storage	Storage	171.7	99.3	204.0	128.6	169.9	
10	Utilization	Dist Ops	146.5	148.5	153.2	166.3	168.4	
11	EA Fixed Overhead	Other	21.9	22.2	22.5	22.9	23.2	
12	Community Expansion	Growth	24.4	27.4	11.2	7.0	7.3	
13	Other	Other	40.8	35.7	35.7	35.7	35.7	/u
14	Total		1,491.3	1,471.1	1,435.6	1,229.5	1,279.5	/u

Notes:
(1) Expenditures are shown by Asset Class inclusive of IDC and Overheads and net of contributions
(2) Expenditures are shown on an annual basis

4. This Exhibit provides an overview of the capital expenditures that are set out in the AMP provided at Exhibit 2, Tab 6, Schedule 2. Additional details including asset strategies, the Asset Investment Planning & Management (AIPM) process and business cases for individual projects can be found in the AMP.

5. The AMP also details the Integrated Resource Planning (IRP) Framework assumptions included for planning purposes as a result of the IRP Decision[2]. Enbridge Gas follows the AIPM process to initiate the IRP assessment process in order to determine the preferred solution to meet specific system needs. IRP assessments do not apply to non-gas carrying assets. All other investments are subject to IRP Binary Screening through the IRP assessment process. Of the 2,278 investments that were evaluated through Enbridge Gas's IRP Binary Screening, 878 investments passed the screening, relating to $10.4 billion worth of projects that will progress to the technical evaluation. Further information on Enbridge Gas's IRP assessments is provided at Exhibit 2, Tab 6, Schedule 2, Section 6.3, pages 280-288.

6. While the AMP forecast includes all the capital investments required for facility projects, there will be some investments that are delayed or no longer required as a result of implementing Integrated Resource Planning Alternatives (IRPA). The OEB-approved IRP Deferral accounts will be used to capture the costs associated with implementing IRPAs.

2. 2024 Test Year Capital Expenditures Forecast

7. The 2024 Capital Budget was developed following the process outlined in the Utility System Plan (USP). The USP is provided at Exhibit 2, Tab 6, Schedule 1. The objective of the budget process is to ensure a proper governance structure and level of management oversight to enable Enbridge Gas to invest capital efficiently and effectively. The budget is developed in accordance with the Company's strategic priorities of safety and operational reliability while also ensuring compliance with legislative and regulatory requirements and adapting to energy

[2] EB-2020-0091, Decision and Order, July 22, 2021.

transition over time.

8. The AMP underpins the capital budget and identifies the majority of the Company's capital requirements. The AMP outlines the Asset Management process within Enbridge Gas and details a 10-year plan to manage assets from 2023 to 2032. The investment identification process identified more requirements than could be accommodated within the optimization target established for 2024. As a result, some investments were deferred to future years. This includes deferring the start of the Vintage Steel Replacement Program to 2027, the Hagar Boil Off Gas Recovery Project and several investments in the Real Estate and Workplace Services, Compression Station, Transmission Pipe and Underground Storage and Technology & Information Services asset classes.

9. Other inputs to the capital plan include the determination of overhead allocations, Community Expansion projects, regulated RNG and CNG projects and the allocation of capital to Enbridge Gas's unregulated operations.

10. As shown in Table 1, the forecasted expenditure for the 2024 Test Year is $1,491.3 million. These expenditures represent the needs identified and prioritized in the AMP to ensure the safety and reliability of the Enbridge Gas system. This includes expenditures for supporting the demand for customer and system growth, maintaining pipeline integrity of the distribution and transmission systems, ensuring compliance with regulations, investing in Enbridge Gas facilities and expenditures related to system changes as a result of implementing rebasing proposals and technology investments to ensure continued reliability and security. Enbridge Gas is also committed to investing in energy transition, including low-carbon strategies to reduce greenhouse gas emissions and renewable energy opportunities to "green the grid". Information on Enbridge Gas's Energy Transition Plan is provided at /u

Exhibit 1, Tab 10, Schedule 6.

11. The following sub-sections provide a discussion of the capital expenditure budget by asset class.

2.1. Growth Projects

12. The budget for Growth includes Customer Connections, System Reinforcements including Hydrogen Blending (Phase 2 of the Low Carbon Energy Project) and Community Expansion. The 2024 capital budget includes expenditures of $378.7 million for Growth Projects. Section 5.1.3 of the AMP provided at Exhibit 2, Tab 6, Schedule 2, page 64, outlines the Growth Strategy Overview for Enbridge Gas.

13. Customer Growth continues to drive capital requirements with approximately 40,000 customers forecast to be added in 2024. Enbridge Gas recognizes that future legislation and concerns regarding the environment and climate change may lead to changes in customer behaviour(s) and the use of natural gas over time. The long-range forecast that underpins the Customer Connection forecast in the AMP shows a gradual decline in the annual number of customer attachments over the 10-year planning period. Section 5.1.4.3 of the AMP provided at Exhibit 2, Tab 6, Schedule 2, pages 67-68, outlines the 10-year customer additions forecast for Enbridge Gas and the energy transition forecasting assumptions for customer additions is provided at Exhibit 1, Tab 10, Schedule 4. The reduction to capital requirements resulting from energy transition forecasting are minimal and not currently reflected in the 2024 Test Year budget. However, energy transition impacts are expected to become more significant in subsequent years. The resultant change to capital requirements for customer connections will be re-assessed and reflected in future budgets and forecasts.

14. Enbridge Gas is proposing to harmonize the customer connection policy effective January 1, 2024. Details on the harmonized customer connection policy are provided at Exhibit 1, Tab 15, Schedule 1, Attachment 1. The budget is derived based on a portfolio approach to ensure that feasibility guidelines are met as set out in E.B.O. 188. The methodology is further described in Section 5.1.4 of the AMP, provided at Exhibit 2, Tab 6, Schedule 2 pages 64-68. The 2024 Test Year capital expenditure for Customer Connections is $249.2 million.

15. Community Expansion projects install gas distribution assets in communities that have not previously had access to natural gas. In June 2021, the Government of Ontario announced funding for community expansion and economic development projects under phase 2 of the Natural Gas Expansion Program (NGEP). Enbridge Gas was awarded $214 million to support the development of 25 phase 2 communities and 2 economic development projects with total estimated capital of $335 million (net investment of $121 million). The budget includes Community Expansion projects as approved under phase 2. Capital expenditures for these projects are forecasted with the approved spend net of government funding. Community Expansion investments are not included in the Capital Expenditure of Enbridge Gas's AMP, provided at Exhibit 2, Tab 6, Schedule 2, Section 6.2. Enbridge Gas has adjusted the in-service dates to reflect the most likely construction timeline and will start all projects ahead of the 2025 mandated requirement for the start of project execution. The 2024 Test Year capital expenditure for Community Expansion is $24.4 million.

16. System reinforcement projects are required to maintain minimum pressures and ensure that demand for natural gas can be met under design day scenarios. Projects are evaluated to ensure they meet the criteria of E.B.O. 188 and E.B.O. 134 as applicable. All reinforcement projects are subject to binary screening

through the IRP assessment process and where feasible, non-pipe alternatives may be implemented in place of a reinforcement. Significant Distribution System reinforcements for 2024 include East Kingston Creekford Rd Reinforcement, Wheatley 1B Panhandle Distribution Reinforcement and the Hamilton Industrial Reinforcement Project. The 2024 Test Year capital expenditure for system reinforcement is $105.1 million.

17. Enbridge Gas is investing in low-carbon technologies and energy solutions to keep energy reliable and affordable and reduce impacts on the environment. In 2021, the Low Carbon Energy Project (LCEP) was completed in Markham. In 2024, phase 2 of the LCEP is expected to begin which includes expanding hydrogen blending to an additional 12,400 customers. Enbridge Gas will also conduct a study to identify and prioritize which sections of the gas grid are best suited for future hydrogen blending projects and determine any required upgrades. The Enbridge Gas hydrogen strategy is provided at Exhibit 4, Tab 2, Schedule 6. Section 3.3 of the AMP provided at Exhibit 2, Tab 6, Schedule 2, page 35 describes how low-carbon technologies and energy transition are included in the AMP. The 2024 Test Year capital expenditure for hydrogen blending of $8.9 million is included within the system reinforcement spend of $105.1 million.

2.2. Distribution Operations

18. The budget for Distribution Operations includes the Distribution Pipe, Distribution Stations and Utilization asset classes. The 2024 capital budget includes expenditures of $635.4 million. The strategies for Distribution Pipe, Distribution Stations and Utilization are in the AMP provided at Exhibit 2, Tab 6, Schedule 2, Sections 5.2.3.2, 5.2.4.2 and 5.2.5.4 respectively. Investments include the maintenance and renewal of pipeline assets, station assets and measurement systems.

19. Enbridge Gas has a strong focus on evaluating the current and future requirements of existing distribution and transmission assets and the need to ensure safe and reliable delivery of natural gas to customers. This includes strategies related to the maintenance and replacement or renewal of distribution and transmission assets. The Distribution Integrity Management Program (DIMP) and Transmission Integrity Management Program (TIMP) identify system integrity and reliability risks with Enbridge Gas's pipeline assets which are then prioritized based on risk to determine the timing of investments. The outcomes of the DIMP and TIMP assessments determine the need to maintain or replace pipeline assets. In response to the St. Laurent LTC Decision[3] and direction from the OEB, Enbridge Gas is also re-evaluating the current DIMP Assessment Program and plans to introduce the Enhanced Distribution Integrity Management Program (Enhanced DIMP) with the goal of providing more detailed pipeline condition assessments. The Enhanced DIMP and the proposed financial treatment is provided at Exhibit 1, Tab 13, Schedule 3. Additionally, the IRP Assessment process will be used to evaluate the preferred facility solution and compare it to IRP alternatives to meet the specific system needs. Significant investments included in the 2024 capital budget include the St. Laurent Phase 3 – North/South Replacement, the NPS 8 Port Stanley Replacement (both with expected in-service of 2024) and initial costs for the Wilson Avenue, Toronto, VSM Replacement which is expected to be in-service in 2025. The decision to repair or replace the St. Laurent Pipeline is dependent on the outcome of the investigative work to be completed in 2022. The 2024 Test Year capital expenditure for Distribution Pipe is $368.3 million.

20. Distribution Station investments include the Facilities Integrity Management Program (FIMP), investments to replace or renew stations with Auxiliary Equipment,

[3] EB-2020-0293, Decision and Order, May 3, 2022.

Distribution System Stations and Customer Station assets, CNG and RNG Stations. The IRP Assessment process is used to evaluate the preferred facility solution for station replacements and renewals and compare it to IRPAs to meet the specific system needs. The 2024 Test Year capital expenditure for Distribution Stations is $120.6 million.

21. Enbridge Gas has constructed customer driven CNG Rental Station and RNG Injection Station projects. As RNG becomes more available, Enbridge Gas will pursue opportunities to inject RNG into the Distribution System. CNG and RNG stations are part of Enbridge Gas's low-carbon strategy.

22. Investments related to utilization include meter purchases, the Meter Exchange Government Inspection (MXGI) Program, and regulators. Expenditures are driven by the demand for new meters related to the customer additions, the replacement of meters (MXGI) and regulator refits. Expenditures have increased due to supply chain issues related to COVID-19. These supply chain issues have resulted in a decrease in the availability of diaphragm meters which required Enbridge Gas to source alternate meters. Enbridge Gas launched a pilot program for Advanced Metering Infrastructure (AMI) in 2022. Results from the pilot will be used to define the scope of the AMI Project which will be incorporated into future Asset Management Plans. More information on Enbridge Gas's AMI strategy is provided at Exhibit 2, Tab 7, Schedule 2. The 2024 Test Year capital expenditure for utilization is $146.5 million.

2.3. Storage and Transmission Operations

23. The budget for Storage and Transmission Operations includes the Compression Stations and Transmission Pipelines and Underground Storage asset classes. The 2024 Test Year capital for Storage and Transmission Operations is $210.6 million.

Section 5.3.4 of the AMP provided at Exhibit 2, Tab 6, Schedule 2, page 180 describes the strategy for Storage and Transmission Operations.

24. Enbridge Gas maintains a large fleet of compressors that operate to inject and withdraw natural gas from storage operations and transport natural gas along its network of transmission pipelines. Investments are required to both maintain and modernize the compressor fleet. Significant projects in 2024 include development work required for the Dawn C Compression Lifecycle with an expected in-service in 2026. The 2024 Test Year capital expenditure for compression stations is $38.9 million.

25. Investments related to the Transmission Pipe and Underground Storage asset class include integrity projects required to maintain storage assets, replacements for pipelines and well equipment and growth-related reinforcement projects. A significant maintenance project in 2024 is the Panhandle Line Replacement Project. Anticipated growth-related reinforcement projects for 2024 include the Panhandle Regional Expansion Project – Leamington Interconnect and development work for the Dawn-Parkway Expansion Project (Kirkwall-Hamilton NPS 48). The IRP Assessment Process is used to evaluate the preferred facility solution and compare it to IRP alternatives to meet the specific system needs. The 2024 Test Year capital expenditure for Transmission Pipe and Underground Storage is $171.7 million.

2.4. Real Estate, Technology and Information Systems and Fleet

26. The Real Estate and Workplace Services (REWS) asset class has forecasted expenditures of $56.6 million for the 2024 budget. This includes expenditures related to workplace furnishings, building systems management, land purchases, the construction of new facilities or renovations to current buildings and opportunities to improve energy efficiency. Section 5.4.4 of the AMP, provided at

Exhibit 2, Tab 6, Schedule 2, page 212, summarizes the REWS strategies for the maintenance and replacement of assets. Significant projects in 2024 include the construction for the Kennedy Road Expansion which is expected to be completed in 2025 and the completion of construction for the Station B New Building (Toronto) and South Merivale Operations Centre (SMOC)/Coventry Facility Consolidation (Ottawa).

27. The Technology and Information Systems (TIS) asset class is driving an increase in expenditures for the 2024 budget with a spend of $112.4 million. TIS expenditures support system operations while reducing operational and cybersecurity risks. Investment is required to ensure reliability and enhance systems, processes and procedures for the integrated utility to address evolving business needs and implement changes as a result of 2024 Rebasing. Section 5.6.4 of the AMP provided at Exhibit 2, Tab 6, Schedule 2, pages 238-240 summarizes the TIS strategy overview which includes investments in infrastructure, software and communication devices. Significant projects in 2024 include the Contract Market Harmonization, Contract Market Systems – Technology Obsolescence, General Service Rebasing Changes and the Records Management Upgrade (2024 to 2026). These projects address technology obsolescence and the required upgrades in order to drive efficiencies for the existing Enbridge Gas rate zones.

28. The Fleet and Equipment asset class has forecasted expenditures of $35 million for the 2024 Test Year. This category includes vehicles, equipment and tools required to conduct business operations safely and efficiently. Section 5.5.4 of the AMP provided at Exhibit 2, Tab 6, Schedule 2, page 229 outlines the strategy for the maintenance and replacement of these assets. Enbridge Gas has a maintenance program to sustain the fleet. This program uses risk, cost and

performance information to drive asset replacement decisions. Section 5.5.5.1 of the AMP provided at Exhibit 2, Tab 6, Schedule 2, page 230 describes the assessment process used to determine the repair vs replace decision for assets.

3. Summary

29. Enbridge Gas is forecasting 2024 Test Year capital expenditures of $1,491.3 million to support customer growth, maintain distribution, transmission and storage assets and invest in the technology requirements to address obsolescence, cybersecurity threats and the implementation of rebasing proposals. The IRP Assessment process will be applied to qualifying projects in order to determine the appropriate facility solution. The AMP further describes the specific strategies by asset class and includes business cases to support significant investments. The forecast capital expenditures address the safety, reliability and customer requirements for Enbridge Gas. /u

CAPITAL EXPENDITURE HISTORY

DANIELLE DREVENY, MANAGER CAPITAL FINANCIAL PLANNING & ANALYSIS
BOB WELLINGTON, MANAGER ASSET MANAGEMENT GOVERNANCE AND RISK

1. The purpose of this evidence is to present a summary of capital expenditures for EGD and Union for 2013 to 2018 which includes the incentive regulation (IR) terms from 2014 to 2018 for each respective utility. This evidence also provides a summary of capital expenditures for Enbridge Gas for the deferred rebasing term and the 2024 Test Year.

2. Capital expenditures are required to ensure the ongoing safe and reliable delivery of natural gas while economically attaching new customers. Prior to amalgamation, both EGD and Union followed similar approaches in prioritizing capital expenditures under their respective IR frameworks.

3. This evidence is organized as follows:
   1. Introduction
   2. Summary of Capital Expenditures 2013 to 2018 – EGD
   3. Summary of Capital Expenditures 2013 to 2018 – Union
   4. Year-over-Year Variance Analysis of Capital Expenditures 2019 to 2024 – Enbridge Gas

1. Introduction

4. As provided at Exhibit 2, Tab 5, Schedule 1, the level of capital expenditures varies from year to year largely due to significant replacement and reinforcement projects and the timing of the execution of these projects. However, the underlying base capital expenditures were stable over the 2013 to 2018 period for both EGD and Union as well as over the deferred rebasing term for Enbridge Gas.

5. Table 1 provides a summary of the Earning Sharing Mechanism (ESM)[1] docket numbers for EGD, Union and Enbridge Gas from 2014 to 2021. Comparisons of actual capital expenditures to OEB-approved capital expenditures were provided in the EGD and Union ESM proceedings. Actual capital expenditures are provided in the Enbridge Gas ESM proceedings.

Table 1
Earning Sharing Mechanism Filings

Line No.	Earnings Sharing Docket	Utility and Reporting Year
1	EB-2015-0122	EGD - 2014
2	EB-2015-0010	Union - 2014
3	EB-2016-0142	EGD - 2015
4	EB-2016-0118	Union - 2015
5	EB-2017-0102	EGD - 2016
6	EB-2017-0091	Union - 2016
7	EB-2018-0131	EGD - 2017
8	EB-2018-0105	Union - 2017
9	EB-2019-0105	EGI - 2018
10	EB-2020-0134	EGI - 2019
11	EB-2021-0149	EGI - 2020
12	EB-2022-0110	EGI - 2021

6. Enbridge Gas received OEB approval to amalgamate in 2018 under the Mergers, Acquisitions, Amalgamations and Divestitures (MAADs) Decision[2] with a 5-year deferred rebasing term from 2019 to 2023. Integration capital expenditures which were required to amalgamate EGD and Union were incurred over the 2019 to 2023 period and included in the annual ESM fillings. Integration capital projects were not eligible in the determination of annual Incremental Capital Module (ICM) amounts

[1] ESM in this context refers to the annual deferral and variance account clearing applications filed by EGD, Union and Enbridge Gas.
[2] EB-2017-0306, EB 2017-0307.

and were not recovered through base rates during the deferred rebasing term. Exhibit 1, Tab 9, Schedule 1 provides information regarding utility consolidation activities including details on integration capital projects.

7. Through careful consideration of capital expenditures, Enbridge Gas has continued to provide safe and reliable service to its customers. The evidence that follows provides further information on capital expenditures over the 2013 to 2018 and 2019 to 2024 time periods.

2. Summary of Capital Expenditures 2013 to 2018 – EGD

8. Table 2 provides a summary of EGD capital expenditures from 2013 to 2018. As provided at Exhibit 2, Tab 5, Schedule 1, EGD operated under a Custom IR[3] framework during the 2014 to 2018 period which included approved capital budgets for 2014 to 2016. The 2016 budget informed the expected spend for the 2017 and 2018 budgets. EGD filed annual ESM applications which described the variances in spend between actual and budgeted capital expenditures.

[3] EB-2012-0459.

Table 2
Utility Capital Expenditures – EGD 2013 to 2018

Line No.	Particulars ($ millions)	Utility	2013 OEB-Approved	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Customer Related Distribution Plant	EGD	123.0	146.4	160.2	145.5	153.0	141.3	150.3
2	System Improvements and Upgrades	EGD	193.1	216.1	184.5	208.5	224.0	214.1	198.2
3	General and Other Plant	EGD	47.6	53.2	54.5	55.8	45.6	49.4	49.2
4	Underground Storage Plant	EGD	22.4	25.9	13.4	26.9	18.2	19.8	15.6
5	Sub total		386.1	441.6	412.6	436.7	440.8	424.6	413.3
6	Work and Asset Management Solution	EGD	0.5		19.6	27.6	38.3	2.0	0.0
7	Leave to Construct – GTA Reinforcement	EGD	63.3	14.3	172.4	551.1	114.8	4.8	0.0
8	Leave to Construct – Ottawa Reinforcement	EGD		61.9	7.7	0.0	0.0	0.0	0.0
9	Total		449.9	517.8	612.3	1,015.4	593.9	431.4	413.3

9. Table 3 compares actual vs budgeted EGD capital expenditures for the period of 2013 to 2018. Base capital expenditures represent the ongoing capital requirements to maintain the safe and reliable operations of the Enbridge Gas system and to economically attach new customers. In addition to the base capital expenditures EGD had three significant special projects over the 2013 to 2018 timeframe: the GTA Reinforcement, the Ottawa Reinforcement and the Work and

Asset Management Solution (WAMS) Project.

Table 3

Utility Capital Expenditures - EGD 2013 to 2018 Actual vs Budget

Line No.	Particulars ($ millions)	2013	2014	2015	2016	2017	2018	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	OEB-Approved Budget – Base Capital Expenditures	386.1	443.8	446.6	442.3	441.9	441.9	2,602.6
2	EGD Actual Base Capital Expenditures	441.6	412.6	436.7	440.8	424.6	413.3	2,569.6
3	Total over/(under) spend	55.5	(31.2)	(9.9)	(1.5)	(17.3)	(28.6)	(33.0)
4	OEB-Approved Budget - GTA Project	19.3	307.0	359.7	0.0	0.0	0.0	686.0
5	EGD Actual Expenditures - GTA Project	14.3	172.4	551.1	114.8	4.8	0.0	857.4
6	Total over/(under) spend	(5.0)	(134.6)	191.4	114.8	4.8	0.0	171.4
7	OEB-Approved Budget - WAMS Project	0.5	36.3	25.7	7.6	0.0	0.0	70.1
8	EGD Actual Expenditures - WAMS Project	2.6	19.6	27.6	38.3	2.0	0.0	90.1
9	Total over/(under) spend	2.1	(16.7)	1.9	30.7	2.0	0.0	20.0
10	OEB-Approved Budget - Ottawa Reinforcement	44.0	5.1	0.0	0.0	0.0	0.0	49.1
11	EGD Actual Expenditures - Ottawa Reinforcement	61.9	7.7	0.5	0.0	0.0	0.0	70.1
12	Total over/(under) spend	17.9	2.6	0.5	0.0	0.0	0.0	21.0

Note:

(1) The approved LTC for Ottawa reinforcement was $51 million

10. EGD capital expenditures were consistently under the base capital expenditure amounts included in the overall OEB-approved capital expenditure budget during the 5-year Custom IR period. During this timeframe Enbridge Gas effectively managed cost pressures and prioritized capital projects.

11. Capital expenditures tended to be over budget for areas such as Customer Connections, Storage and Facilities and General Plant. Customer Connections exceeded the budget due to cost pressures related to customer mix and higher unit costs. Storage costs exceeded budget due to timing of construction projects and spend related to repairing degrading compressor units. Facilities and General Plant costs exceeded budget due to investment in fleet vehicles and tools to meet reliability and safety concerns as well as investment in facilities. Costs were offset in the areas of reinforcements, overheads, TIS spend, Integrity and relocation projects. Reinforcements spend was reduced due to project deferrals associated with growth including the deferral of the York Region reinforcement project. Overheads costs were lower due to productivity savings as a result of reductions in FTEs and lower Interest During Construction (IDC) as a result of delayed spend on significant projects. TIS spend was reduced due to reprioritization of spend as a result of ongoing business requirements. Integrity spend was lower due to the adoption of new Asset Management portfolio prioritization processes using risk-based assessments. Relocations were lower due to third party recoveries for projects.

12. The GTA Reinforcement[4] project involved the construction of two segments of underground pipeline and associated facilities. The first segment of approximately 21 km of pipeline was located in the town of Milton. The second segment of

[4] EB-2012-0451.

approximately 23 km of pipeline was located in the City of Vaughan. The project was required to reinforce the EGD system in order to meet forecasted growth for 2015 to 2025 and also provided the benefit of reducing operational risk and enhancing safety and reliability by improving the diversity and flexibility of the distribution system. The project reduced the dependence on the Parkway Gate Station, improved supply chain diversity, reduced upstream supply risks and reduced expected gas supply costs by $1.6 billion over the 2015 to 2025 period. The GTA project was $171.4 million over budget due to several factors including escalation of the construction bid price, increased costs associated with greater construction complexity and increased overall duration due to longer permit acquisition times. However, the forecasted reduction of gas supply costs and overall benefits delivered by the execution of the project outweigh the cost overruns. Additional details regarding project costs were filed in the Post Construction Financial Report for the GTA Project[5].

13. WAMS project is a business tool for ensuring safe and reliable service to EGD customers. WAMS replaced obsolete technology that supported over 1 million work requests annually and stored asset records for over 2 million customers. The project was executed over 2014 to 2016 with ‘go-live’ in October of 2016. Spend in 2014 was delayed due to a delay in starting the implementation phase, this pushed costs into 2015 resulting in higher spend than budget. Ultimately the project was completed for $90.1 million compared to a budget of $70.1 million primarily driven by delays as a result of design complexities. However, the benefits delivered by implementing the WAMS tool outweighed the cost overruns. Benefits included

[5] The Post Construction Financial Reports for the GTA Project can be found on the OEB website at the following link: https://www.rds.oeb.ca/CMWebDrawer/Record?q=casenumber:eb-2012-0451&sortBy=recRegisteredOn-&pageSize=400#form1

technology obsolescence risk mitigation, increased auto invoicing, improved insight to progressing work and better tracking of restorations.

14. The Ottawa Reinforcement Project[6] involved the construction of approximately 18.8 km of NPS 24 extra high pressure pipeline and ancillary facilities. The project increased capacity of the Ottawa area distribution system to meet existing and forecasted demand loads, provide additional security of supply and operational flexibility. The project was $18.9 million over budget due to several factors including increased labour costs for inclement weather, inability to secure planned working easements, unplanned rock excavation, increased materials costs from pipe coating changes and shipping delays, and increased external costs for inspection and permitting resources and the use of external consultants. Additional details regarding project costs were filed in the Post Construction Financial Report for the Ottawa Reinforcement Project[7].

15. Overall, including the Special Initiative and LTC projects, EGD exceeded approved spend by $179.4 million over the 2013 to 2018 period largely driven by the complexities of the GTA Project. This amounts to approximately a 5% variance on rate base additions of over $3.5 billion.

3. Summary of Capital Expenditures 2013 to 2018 – Union

16. Table 4 provides a summary of Union capital expenditures from 2013 to 2018. As provided at Exhibit 2, Tab 5, Schedule 1, Union operated under a Price Cap IR[8] framework during the 2014 to 2018 period and used a Capital Pass Through (CPT)

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[6] EB-2012-0099.
[7] The Post Construction Financial Reports for the Ottawa Reinforcement Project can be found on the OEB website at the following link:
https://www.rds.oeb.ca/CMWebDrawer/Record/477849/File/document
[8] EB-2013-0202.

mechanism for projects outside of approved base rates. Union filed annual ESM applications which compared spend relative to the 2013 OEB-approved budget and the prior year actual.

Table 4
Utility Capital Expenditures - Union 2013 to 2018

Line No.	Particulars ($ millions)	Utility	2013 OEB-Approved	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Storage	Union	11.6	5.7	7.4	5.9	158.9	91.6	25.7
2	Transmission	Union	113.8	106.6	191.1	394.9	583.3	316.5	95.7
3	Distribution	Union	131.8	164.9	162.4	173.0	182.5	197.4	270.7
4	General	Union	37.2	35.2	47.8	44.5	30.4	34.9	43.9
5	Overheads	Union	53.3	55.7	68.3	73.1	78.8	80.5	83.2
6	Sub total		347.7	368.2	476.9	691.3	1,034.0	721.0	519.2
	Less: Capital Pass Through Projects								
7	Parkway West Reliability	Union	80.0	42.1	99.3	68.2	16.4	1.4	1.1
8	Parkway D & Brantford-Kirkwall Projects	Union		10.1	39.8	138.1	7.8	1.6	0.0
9	2016 Dawn-Parkway Growth Project	Union		0.0	14.2	91.5	222.5	17.2	2.3
10	Burlington-Oakville Pipeline	Union		0.4	1.2	3.5	74.0	2.7	1.5
11	2017 Dawn-Parkway Project	Union		0.0	0.1	51.5	363.0	159.7	39.5
12	Panhandle Reinforcement	Union		0.0	0.0	0.0	7.1	182.4	36.6
13	Sudbury Replacement Project	Union		0.0	0.0	0.0	0.0	2.9	75.1
14	Total		267.7	315.6	322.3	338.7	343.2	353.1	363.1

17. Union capital expenditures, excluding CPT projects, were prioritized and managed during Union's IR framework by escalating the 2013 OEB-approved capital expenditure budget with inflation. Over the IR term capital expenditures excluding CPT were stable with moderate increases.

18. Union had higher capital expenditures for Growth due to higher customer attachment costs and reinforcement projects driven by system demand growth, such as the Leamington Phase 2 Reinforcement in 2015. Real Estate and Workplace Services (REWS) had higher expenditures in 2014 and 2015 due to extensive renovation to the Bloomfield Road Education Centre in the Municipality of Chatham-Kent. The Technology and Information Services (TIS) had an increase in spend in 2014 to 2018 due to investment in the Contrax Modernization Project, which upgraded the technology to interact with Storage & Transportation, large commercial & industrial and direct purchase customers. In 2017 and 2018, increases were driven by the Bruce Lake Lateral and Sudbury Lateral[9] projects. The Sudbury Project was expected to go into service in October of 2018 and fell between qualifying for CPT vs ICM funding. Enbridge Gas applied for ICM recovery for the Sudbury project as part of the 2019 Rates[10] Application, however the OEB determined that the project should be treated as CPT since ICM funding only applied to projects with a 2019 in-service date.

19. CPT projects were the most significant area of spend over the 2014 to 2018 period driven primarily by the need to expand Union's Dawn-Parkway System. Table 5 summarizes the CPT projects completed during Union's IR term.

[9] EB-2017-0180.
[10] EB-2018-0305.

Table 5
Utility Capital Expenditures - Union Capital Pass-Through Projects 2013 to 2018

Line No.	Particulars ($ millions)	Utility	LTC Budget	Actual Spend	Variance
			(a)	(b)	(c) = (a-b)
1	Parkway West Reliability	Union	203.1	228.4	(25.3)
2	Parkway D & Brantford-Kirkwall Projects	Union	204.1	197.3	6.7
3	2016 Dawn-Parkway Growth Project	Union	390.7	347.8	42.9
4	Burlington-Oakville Pipeline	Union	119.5	83.3	36.2
5	2017 Dawn-Parkway Project	Union	622.5	613.8	8.7
6	Panhandle Reinforcement	Union	264.5	226.2	38.3
7	Sudbury Replacement Project	Union	74.0	78.0	(4.0)
8	Total		1,878.3	1,774.8	103.5

20. The Dawn-Parkway projects were required to address the shift in supply dynamics from the western supply basin to the Marcellus shale and the market shift from long- haul to short-haul transportation. The Parkway West Reliability[11] Project included a new compressor site at Parkway West, installation of an interconnect to the Parkway site and a loss of critical unit compressor. The Parkway D & Brantford-Kirkwall Project[12] added a compressor unit to the Parkway West site and 13.8 km of NPS 48 pipeline from Brantford to Kirkwall. The 2016 Dawn-Parkway Growth Project[13] added a compressor unit at the Lobo compressor site and approximately 20 km of NPS 48 pipeline from the Hamilton valve site to the Milton valve site. The Burlington-Oakville Project[14] included the installation of approximately 12 km of NPS 20 pipeline from the Parkway West Compressor Station to the Bronte Gate Station. Finally, the 2017 Dawn-Parkway Project[15] included the installation of

[11] EB-2012-0433.
[12] EB-2013-0074.
[13] EB-2014-0261.
[14] EB-2014-0182.
[15] EB-2015-0200.

additional compressor units at the Dawn, Lobo and Bright compressor sites. Overall, the Dawn to Parkway CPT projects increased system capacity to 7,904,420 GJ/d in order to meet the forecasted demand of 7,874,027 GJ/d with a remaining surplus of 30,393 GJ/d and were completed $69.2 million below the estimated LTC costs as of December 31, 2018.

21. The Panhandle Reinforcement Project[16] was required to address significant growth of in-franchise customers served by the Panhandle System, particularly with the Greenhouse market in southwestern Ontario. The project included approximately 40 km of NPS 36 pipeline from the Dawn Compressor Station to the Dover Transmission Station and station modifications to support incremental capacity requirements of 106 TJ/d. The project was completed in 2017 and was $38.3 million under the forecasted costs as of December 31, 2018.

22. The Sudbury Replacement Project[17] was required to address pipeline integrity issues and future growth requirements. The project included the replacement of approximately 19.8 km of pipeline over 2 sections of the Sudbury lateral and upsizing the pipe from NPS 10 to NPS 12. The project was completed in 2018 and was $4 million over the forecasted costs as of December 31, 2018.

23. Overall, excluding the CPT projects, Union capital expenditures during the 2014 to 2018 IR term were stable with moderate increases.

[16] EB-2016-0186.
[17] EB-2017-0180.

4. Year-over-Year Variance Analysis of Capital Expenditures 2019 to 2024 - Enbridge Gas

12. The following sections of this Exhibit provide detailed variance explanations for Enbridge Gas's capital expenditures from 2019 to the 2024 Test Year Forecast. Table 6 summarizes the expenditures from 2019 to 2024.

Table 6
Utility Capital Expenditures by Asset Class 2019 Actual -2024 Test Year

Line No.	Particulars ($ millions)	Utility	2019 Actual	2020 Actual	2021 Actual	2022 Estimate	2023 Bridge Year	2024 Test Year	
			(a)	(b)	(c)	(d)	(e)	(f)	
1	Compression Stations	EGI	25.5	26.5	42.3	87.7	239.2	38.9	
2	Customer Connections	EGI	190.4	178.7	260.7	220.7	220.4	249.2	
3	Distribution Pipe	EGI	175.1	192.8	447.2	458.5	261.9	368.3	
4	Distribution Stations	EGI	39.7	61.4	91.2	106.6	149.3	120.6	
5	Fleet & Equipment	EGI	26.3	20.2	26.7	30.6	25.5	35.0	
6	Growth - Distribution System Reinforcement	EGI	144.1	70.0	48.5	52.6	54.9	105.1	
7	Real Estate & Workplace Services	EGI	42.0	38.3	70.5	118.7	52.1	56.6	
8	Technology Information Services (TIS)	EGI	48.9	22.7	22.8	39.4	63.7	112.4	
9	Transmission Pipe and Underground Storage	EGI	20.3	33.5	79.5	102.5	280.7	171.7	
10	Utilization	EGI	99.3	62.9	80.7	120.3	136.5	146.5	
11	Extended Alliance Fixed Overhead	EGI	17.8	19.5	25.4	21.3	21.7	21.9	
12	Capitalized Overheads	EGI	215.2	220.9	0.0	0.0	0.0	0.0	
13	Integration Capital	EGI	21.7	39.8	87.5	41.6	43.6	0.0	
14	Community Expansion	EGI	17.1	20.9	17.4	20.7	14.0	24.4	
15	Other	EGI	3.9	(0.9)	10.5	22.9	42.0	40.8	/u
16	Total		1,087.4	1,007.2	1,310.8	1,444.3	1,605.7	1,491.3	/u

Notes:
(1) Capital expenditures are shown on an annual basis
(2) Expenditures are net of contributions and include IDC
(3) Overheads are included in the Asset Classes starting in 2021

4.1. 2020 Actual vs 2019 Actual

24. Table 7 provides a comparison of 2019 and 2020 actual capital expenditures for Enbridge Gas. The 2020 actual expenditure of $1,007.2 million is $80.2 million lower than the 2019 actual of $1,087.4 million. This is primarily driven by a reduction in spend on reinforcement projects as a result of completing the Kingsville Reinforcement Project[18] in 2019.

Table 7
Comparison of Utility Capital Expenditures 2019 Actual & 2020 Actual

Line No.	Particulars ($ millions)	2019 Actual	2020 Actual	2020 Actual Over/(Under) 2019 Actual
		(a)	(b)	(c) = (b-a)
1	Compression Stations	25.5	26.5	1.0
2	Customer Connections	190.4	178.7	(11.8)
3	Distribution Pipe	175.1	192.8	17.7
4	Distribution Stations	39.7	61.4	21.6
5	Fleet & Equipment	26.3	20.2	(6.1)
6	Growth - Distribution System Reinforcement	144.1	70.0	(74.1)
7	Real Estate & Workplace Services	42.0	38.3	(3.7)
8	Technology Information Services	48.9	22.7	(26.1)
9	Transmission Pipe and Underground Storage	20.3	33.5	13.2
10	Utilization	99.3	62.9	(36.4)
11	Extended Alliance Fixed Overhead	17.8	19.5	1.7
12	Capitalized Overheads	215.2	220.9	5.7
13	Integration Capital	21.7	39.8	18.1
14	Community Expansion	17.1	20.9	3.8
15	Other	3.9	(0.9)	(4.8)
16	Total	1,087.4	1,007.2	(80.2)

Notes:
(1) Capital expenditures are shown on an annual basis
(2) Expenditures are net of contributions and include IDC

[18] EB-2018-0013.

a) Compression Stations: This asset class includes compression facilities used in the natural gas transmission system to move gas throughout the transmission pipelines and to move gas in and out of storage facilities. It also includes dehydration facilities which are used to remove moisture from natural gas to ensure that the gas entering the transmission system meets the contractual standards for moisture content. Spend remained relatively consistent in 2019 and 2020;

b) Customer Connections: This asset class (a subclass of the Growth asset class in Section 5.1.4 of the Asset Management Plan (AMP)), provided at Exhibit 2, Tab 6, Schedule 2, includes the cost of adding new customers to the distribution system. Costs include materials and installation costs of mains and services as well as the meter and regulator installation at the customer site. The decrease of $11.8 million is related to the OEB's Decision on the Company's 2019 Rates Application[19] and a decrease in residential connections as a result of COVID-19. In its decision, the OEB directed Enbridge Gas to refund customers who were impacted by the change in the Customer Connection Policy implemented in 2015, resulting in a one-time increase in spend of $25.5 million in 2019. This was offset partially by a strong greenhouse market in the Union rate zones, the introduction of the Private Sewer Lateral Locate program and aligning the presentation of costs for the Union rate zones by moving the meter and regulator install costs for new customers from Utilization to Customer Connections.

c) Distribution Pipe: This asset class includes pipelines and components used to transport natural gas within the distribution system or to end-use customers. It includes the cost of maintaining, replacing or renewing steel and plastic pipelines as well as services to customers. The increase of $17.7

[19] EB-2018-0305.

million is primarily due to increases in spend related to the Integrity Program, construction costs related to the Windsor Line Replacement Project[20] and development costs related to the London Line Replacement Project[21]. This is partially offset by a decrease to municipal relocations, fewer service relays and completion of the Don River 30” Pipeline Project[22].

d) Distribution Stations: This asset class includes above grade facilities designed to reduce the operating pressure of natural gas pipelines systems in order to distribute gas to lower pressure pipelines that supply natural gas to cities and towns. The increase of $21.6 million is primarily related to the Blackhorse Gate Project, the Cookstown Gate Project, the Hamilton Gate Project, the Oxford Gate Project and Kitchener Gate Project.

e) Fleet & Equipment: This asset class includes the cost of vehicles, trailers, heavy work equipment and tools owned by Enbridge Gas in order to support business needs. The decrease of $6.1 million is related to a change in spend as a result of standardizing the processes and procedures related to the assignment of vehicles for the appropriate roles, types of vehicles required to support employees in performing their roles, and the vehicle maintenance and repair model in the EGD and Union rate zones.

f) Growth: The Growth asset class includes reinforcements driven by customer and load growth. The decrease of $74.1 million was primarily related to the completion of the Kingsville Transmission and Stratford Reinforcement ICM projects in 2019 offset by the Owen Sound Transmission Project in 2020. 2020 spend was also reduced in both rate zones as a result of construction delays due to new provincial social distancing restrictions and work stoppages related to COVID-19.

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[20] EB-2019-0172.
[21] EB-2020-0192.
[22] EB-2018-0108.

g) REWS: This asset class includes the cost of properties (buildings and land) and furnishings. There is a base spend for each rate zone that supports building repairs and acquisition of furnishings. Variances are driven by the specific land purchases and building renovations that occur in a given year. Land acquisitions are driven by market availability and are aligned with the long-term strategies described in the AMP, provided at Exhibit 2, Tab 6, Schedule 2. The decrease of $3.7 million is primarily related to the timing of land purchases and building renovations. 2020 spend included property purchases of land adjacent to the Kennedy Road facility in Toronto to support planned expansion of the facility and in London to prepare for the construction of a new London facility. In addition to land purchases, there were construction costs related to the new Belleville facility and renovation costs for the Keil Drive facility. This is offset by a decrease in land spend compared to 2019 related to the purchase of land adjacent to the Toronto Operations Centre (TOC) in Markham to prevent encroachment due to urban sprawl on the site.

h) TIS: This asset class includes the cost of general and specialized hardware, software assets consisting of packaged or developed applications and communication assets. The decrease of $26.1 million is related to the completion of the Contrax Modernization, Customer Information System (CIS) Hardware Replacement and Geographic Information System (GIS) upgrade projects in 2019. Base capital spend was reduced as a result of increased activity on integration projects required to merge EGD and Union systems. All spend related to amalgamating systems as driven by utility consolidation is captured under the Integration category.

i) Transmission Pipe and Underground Storage (TPUS): This asset class includes the pipelines that form the backbone of the gas transmission system as well us the underground storage reservoirs in St. Clair Township near

Sarnia, Crowland Township in Welland, and in Chatham-Kent. The increase of $13.2 million is related to replacements driven by the Class Location program as well as an increase in retrofits and integrity digs driven by the Transmission Integrity Management Program (TIMP).

j) Utilization: This asset class includes measurement & regulation systems at customer premises, below ground and internal piping systems after the meter, and customer-owned systems. The decrease of $36.4 million was related to the higher meter installations in 2019, a reduction in meter installations related to COVID-19 in 2020 and aligning the presentation of costs for Union by moving the meter and regulator install costs for new customers from Utilization to Customer Connections.

k) Extended Alliance (EA) Fixed Overhead: The EA fixed overhead asset class includes costs for Alliance partner overheads and district contractor pre-work costs. Spend was relatively consistent in 2019 and 2020.

l) Capitalized Overhead: This category includes the allocation of capitalized O&M and IDC. The increase of $5.7 million is related to the implementation of a harmonized overhead capitalization policy in 2020. The harmonized overhead capitalization policy is provided at Exhibit 2, Tab 4, Schedule 2. The policy change resulted in an increase in the amount of capitalization due to the alignment of capitalization rates for Enbridge Gas partially offset by a reduction in total overheads as a result of reduced O&M spend.

m) Integration Capital: This category includes expenditures required to integrate EGD and Union onto common systems, processes and facilities. A summary of all integration activities undertaken during the deferred rebasing term is provided at Exhibit 1, Tab 9, Schedule 1, Table 2. The spend in 2019 was primarily related to the Customer Experience and CIS Upgrade projects. The increase of $18.1 million in 2020 is related to the CIS Project, the Integrated

Utility Asset & Work Management System Phase 1 (AWS) and the Cost of Gas (COG) projects.

n) Community Expansion: This category captures the expenditures required to expand the natural gas distribution system to include customers that did not previously have access to natural gas. The increase of $3.8 million is related to construction of the Scugog Island First Nation Project partially offset by the completion of the Fenelon Falls Project.

o) Other: This category includes expenditures for CNG Rental Stations, RNG Injection Stations and Hydrogen Blending. The decrease of $4.8 million is primarily due to less spend on the CNG Rental Stations Program in 2020.

4.2. 2021 Actual vs 2020 Actual

25. Table 8 provides a comparison of 2021 and 2020 Actuals for Enbridge Gas. The 2021 actual expenditure of $1,310.8 million is $303.6 million higher than the 2020 actual of $1,007.2 million. This is primarily driven by construction of the London Line Replacement Project[23] and Sarnia Industrial Line Reinforcement[24], integrity spend for retrofits and digs and increased spend on integration projects. Effective 2021, Enbridge Gas changed the presentation of overheads as a separate asset class and began showing the allocation of overheads directly to the applicable asset classes. The presentation of overheads is shown as an allocation to projects based on the total direct capital spend by rate zone. This is consistent with the presentation of overheads in the AMP and ICM applications for 2021. The impact related to the shifting of overheads is included in each Asset Class explanation below. The 2021 total overheads are an increase of $14 million compared to 2020 actual due to an increase in overhead capitalization rates, higher gross O&M expenditures relative to 2020 and higher IDC costs due to multi-year projects.

[23] EB-2020-0192.
[24] EB-2019-0218.

Table 8
Comparison of Utility Capital Expenditures 2020 Actual & 2021 Actual

Line No.	Particulars ($ millions)	2020 Actual	2021 Actual	2020 Actual Over/(Under) 2019 Actual
		(a)	(b)	(c) = (b-a)
1	Compression Stations	26.5	42.3	15.8
2	Customer Connections	178.7	260.7	82.0
3	Distribution Pipe	192.8	447.2	254.4
4	Distribution Stations	61.4	91.2	29.9
5	Fleet & Equipment	20.2	26.7	6.5
6	Growth - Distribution System Reinforcement	70.0	48.5	(21.5)
7	Real Estate & Workplace Services	38.3	70.5	32.1
8	Technology Information Services	22.7	22.8	0.1
9	Transmission Pipe and Underground Storage	33.5	79.5	46.0
10	Utilization	62.9	80.7	17.8
11	Extended Alliance Fixed Overhead	19.5	25.4	5.9
12	Capitalized Overheads	220.9	0.0	(220.9)
13	Integration Capital	39.8	87.5	47.7
14	Community Expansion	20.9	17.4	(3.6)
15	Other	(0.9)	10.5	11.4
16	Total	1,007.2	1,310.8	303.6

Notes:
(1) Capital expenditures are shown on an annual basis
(2) Expenditures are net of contributions and include IDC

a) Compression Stations: The inclusion of overheads is a $7.9 million increase compared to 2020 spend. The remaining increase of $7.9 million is primarily related to construction costs for the Meter Area Upgrade Phase 1 and Phase 2 Projects offset by a year-over-year decrease in strategic land purchases adjacent to Enbridge Gas facilities at Dawn.
b) Customer Connections: The inclusion of overheads is a $49 million increase compared to 2020 spend. The remaining increase of $33 million is primarily

related to an increase in customer additions in the EGD rate zone in 2021 compared to 2020. Both rate zones experienced increases to the cost of labour and materials as a result of inflation rates, supply chain shortages and unfavourable currency exchange rates.

c) Distribution Pipe: The inclusion of overheads is a $83.2 million increase compared to 2020 spend. The remaining increase of $171.2 million is primarily attributable to the start of construction for two significant main replacement projects that were approved through leave to construct applications: the NPS 20 Replacement Cherry to Bathurst[25] and the London Lines Replacement[26]. Both projects are required to address integrity concerns including corrosion and depth of cover issues. The projects were approved for ICM recovery in the 2020 and 2021 Rates applications (London Lines in EB-2020-0181 and NPS 20 Replacement Cherry to Bathurst in EB-2021-0148). In addition to these projects, there was also increased spend related to integrity retrofits and digs as well as relocations for municipal projects.

d) Distribution Stations: The inclusion of overheads is a $17.1 million increase compared to 2020 spend. The remaining increase of $12.8 million is primarily related to the Station Rebuilds B&C Stations Program and increased Integrity assessments required to determine the condition of station components. This is partially offset by a decrease in CNG and Gate, Feeder and A Stations.

e) Fleet & Equipment: The inclusion of overheads is a $5 million increase compared to 2020 spend. The remaining increase of $1.5 million is related to the purchase of the TDW ProStopp tool which improves safety for workers

[25] EB-2020-0136.
[26] EB-2020-0192.

during construction activities. This is partially offset by delays in receiving Fleet vehicles due to supply chain challenges.

f) Growth: The inclusion of overheads is a $9 million increase compared to 2020 spend. The remaining decrease of $30.5 million is related to the completion of the Kingsville and Owen Sound projects in the Union rate zones in 2020 offset by construction related to the Byron Transmission Station and Staples reinforcement projects in 2021.

g) REWS: The inclusion of overheads is a $13.2 million increase compared to 2020 spend. The remaining increase of $18.9 million is related to the investment in lands to execute the SMOC/Coventry facility Consolidation in the City of Ottawa, the Kennedy Road Expansion Project in the City of Toronto and the Belleville property in the City of Belleville. In addition to the land purchases, there were renovations at the Victoria Park location in the City of Toronto and the 50 Keil Drive renovations in the Municipality of Chatham-Kent.

h) TIS: The decrease in spend compared to 2020 is primarily related to the desktop replacement and sustainment program and the shift of costs from Capital to O&M for Microsoft licenses moving from on-premises to subscription-based cloud services, offset by the inclusion of overheads of $4.3 million.

i) TPUS: The inclusion of overheads is a $14.8 million increase compared to 2020 spend. The remaining increase of $31.2 million is primarily related to the Sarnia Industrial Line Project in the Union rate zones. The Sarnia Industrial Line Project was granted leave to construct by the OEB[27]. This project is required to serve the increased demand growth contracted with Nova Chemicals and address future growth in the Sarnia area. Other areas

[27] EB-2019-0218.

of increase include: integrity digs and retrofits, Maximum Operating Pressure (MOP) remediation work at the Wilkesport site and land purchases to prevent encroachment on Enbridge Gas assets.

j) Utilization: The inclusion of overheads is a $15.1 million increase compared to 2020 spend. The remaining increase of $2.7 million is related to an increase in meter purchases in the Union rate zones compared to 2020 as meter purchases from 2020 were advanced to 2019, offset by reductions in the EGD rate zone in planned meter exchanges as a result of supply chain issues.

k) EA Fixed Overheads: The increase of $5.9 million is due to additional planning work related to the Vintage Steel Program.

l) Integration Capital: The increase of $47.7 million is primarily related to the purchase of land for the new GTA West site in the Milton area. The project will dispose of the Brampton Colony Court, Burlington Mainway and Milton facilities and construct a new asset with an estimated in-service of 2023. It is required as a result of boundary realignment in the existing EGD and Union rate zones to efficiently combine the operations teams. In addition to GTA West, there was increased spend related to the completion of the CIS project and ongoing costs related to the COG and AWS projects.

m) Community Expansion: The decrease of $3.6 million is primarily related to a decrease in spend on the Fenelon Falls and Scugog Island projects due to construction completion partially offset by the start of design work for the Community Expansion Phase 2 projects.

n) Other: The increase of $11.4 million is primarily related to the TOC Hydrogen Blending project and increases in the CNG Rental Station program and RNG injection site projects.

4.3. 2022 Estimate vs 2021 Actual

26. Table 9 provides a comparison of the 2022 Estimate compared to 2021 Actual expenditures. The 2022 Estimate expenditure of $1,444.3 million is $133.5 million higher than the 2021 Actual of $1,310.8 million. This is primarily driven by the construction of the NPS 20 Lakeshore Replacement Project[28] and the expected construction of the St. Laurent Ottawa North Replacement Project[29]. The St. Laurent Project is included in the 2022 Estimate due to the timing of the forecast compared to the timing of receiving the OEB decision on the LTC, however it has been removed from opening rate base in 2023 to reflect the decision. This is offset by the completion of the London Line Replacement Project[30] and Windsor Line Replacement Project[31] in 2021. Variances are described below by asset class.

[28] EB-2020-0293.
[29] EB-2020-0136.
[30] EB-2020-0192.
[31] EB-2019-0172.

Table 9
Comparison of Utility Capital Expenditures 2021 Actual & 2022 Estimate

Line No.	Particulars ($ millions)	2021 Actual	2022 Estimate	2022 Estimate Over/(Under) 2021 Actual
		(a)	(b)	(c) = (b-a)
1	Compression Stations	42.3	87.7	45.4
2	Customer Connections	260.7	220.7	(39.9)
3	Distribution Pipe	447.2	458.5	11.3
4	Distribution Stations	91.2	106.6	15.3
5	Fleet & Equipment	26.7	30.6	3.9
6	Growth - Distribution System Reinforcement	48.5	52.6	4.1
7	Real Estate & Workplace Services	70.5	118.7	48.2
8	Technology Information Services	22.8	39.4	16.6
9	Transmission Pipe and Underground Storage	79.5	102.5	23.1
10	Utilization	80.7	120.3	39.6
11	Extended Alliance Fixed Overhead	25.4	21.3	(4.1)
12	Capitalized Overheads	0.0	0.0	0.0
13	Integration Capital	87.5	41.6	(45.9)
14	Community Expansion	17.4	20.7	3.3
15	Other	10.5	22.9	12.5
16	Total	1,310.8	1,444.3	133.5

Notes:
(1) Capital expenditures are shown on an annual basis
(2) Expenditures are net of contributions and include IDC

a) Compression Stations: The increase of $45.4 million is related to the Corunna (SCOR) Meter Area Upgrade Phase 2 Project, initial development costs for the Dawn to Corunna Replacement[32] Project and an increase in spend for Improvement and Replacements projects including the Dawn Dehy.

[32] EB-2022-0086.

b) Customer Connections: The decrease of $39.9 million is related to the variance in the actual costs required to connect customers compared to the AMP budgeting process for this asset class sub-program. While the 2022 Estimate forecasts a decrease in costs as compared to 2021 actuals in Table 9, Enbridge Gas expects that the actual 2022 expenditures will be similar to 2021. Any increases in spend related to Customer Connections are expected to be managed through reductions in spend in other asset classes. Enbridge Gas is actively working to mitigate these cost pressures. Two examples are a revised construction pricing model for this work as well as updates to the Customer Connection Policy that will ensure a more balanced customer contribution with the current cost environment to take effect in 2024. Please see Exhibit 1, Tab 15, Schedule 1 for the revised Customer Connection Policy.

c) Distribution Pipe: The increase of $11.3 million is primarily related to the start of construction for the NPS 20 Replacement Cherry to Bathurst[33] and St. Laurent Ottawa North Replacement projects [34] offset by the completion of 2021 projects including the Windsor Line Replacement Project[35] and London Line Replacement Project[36]. The St. Laurent Project is included as the 2022 Estimate was determined in March of 2022, whereas the decision for the LTC was not received until May 3, 2022. The project has been removed from the 2023 Bridge Year rate base to correct for the assumption change but is included in the 2022 Estimate due to timing of the budget process. Other variance drivers include increased spend in the Integrity Program due to the number of integrity retrofits and digs including: the Sudbury Lateral Line, an increase in relocation projects based on adjustments to the regional

[33] EB-2020-0136.
[34] EB-2020-0293.
[35] EB-2019-0172.
[36] EB-2020-0192.

forecasts offset by a decrease in spend for the Service Relay Program as a result of alliance partner resource constraints.

d) Distribution Stations: The increase of $15.3 million is primarily related to the construction of Gate and Feed projects including: Bayview Feeder, Brampton Gate Station Rebuild and St. John Sideroad Feeder Station. There is also an increase for Station Rebuild & B and C Stations.

e) Fleet and Equipment: The increase of $3.9 million is due to supply chain issues related to COVID-19.

f) Growth: The increase of $4.1 million is due an increase in reinforcement activity as a result of the growth forecast.

g) REWS: The increase of $48.2 million is related to the project timing of new sites including: South Merivale Operations Centre (SMOC), Station B, Kennedy Road and the Dryden Operations Centre.

h) TIS: The increase of $16.6 million is driven primarily by evolving business needs including: Green Button, Content Management Enhancements 2022, Customer Information System Custom Code Update and Meter Reading Handheld Replacements.

i) TPUS: The increase of $23.1 million is due primarily to the construction of the Dawn to Corunna retrofit projects, development work for the Panhandle Regional Expansion Project[37] and increases to the Integrity and Class Location programs. This is partially offset by a decrease in Replacements due to the completion of MOP remediation work and an expected decrease in Strategic Land purchases.

j) Utilization: The increase of $39.6 million is due primarily to an increase in the forecast for meter exchanges and regulator refits in 2022. Supply Chain and

[37] EB-2022-0157.

resource constraints impacted the number of meter exchange and regulator refits in 2021.

k) Integration Capital**:** The decrease in spend of $45.9 million is due to the completion of the CIS and AWS Phase 1 projects in 2021, spend related to the COG Project and the purchase of land for the GTA West Site in 2021. This is partially offset by lower overall spend in 2022 on integration projects including AWS Phase 2, Estimating & Forecasting Accuracy and Leak & Corrosion Systems Integration.

l) Community Expansion: The increase of $3.3 million is the start of construction for Phase 2 projects including: Perth East (Brunner) in the Township of Perth East and Stanley Olde Maple Lane Farm in the City of Ottawa. Additionally, there is development work for 2023 projects including: Bobcaygeon Community Expansion Project[38] in the City of Kawartha Lakes, Haldimand Shores Community Expansion Project [39] in the township of Alnwick/Haldimand, Kenora District (Highway 594) in the District of Kenora and Selwyn in the Township of Selwyn.

m) Other: The increase of $12.5 million is primarily due to expected projects in the CNG Rental Stations program and RNG injection station projects.

4.4. 2023 Bridge Year vs 2022 Forecast

27. Table 10 provides a comparison of the 2023 Bridge Year compared to the 2022 Estimate. The 2023 Bridge Year expenditure of $1,605.7 million is $161.3 million /u
higher than the 2022 Estimate of $1,444.3 million. This is primarily driven by the construction of significant projects including the Panhandle Regional Expansion Project[40] and the Dawn to Corunna Replacement Project[41], partially offset by the

[38] EB-2022-0111.
[39] EB-2022-0088.
[40] EB-2022-0157.
[41] EB-2022-0086.

completion of the NPS 20 Replacement Cherry to Bathurst Project[42]. Variances are described below by asset class.

Table 10
Comparison of Utility Capital Expenditures 2022 Estimate & 2023 Bridge Year

Line No.	Particulars ($ millions)	2022 Estimate	2023 Bridge Year	2023 Bridge Over/(Under) 2022 Estimate	
		(a)	(b)	(c) = (b-a)	
1	Compression Stations	87.7	239.2	151.5	
2	Customer Connections	220.7	220.4	(0.3)	
3	Distribution Pipe	458.5	261.9	(196.6)	
4	Distribution Stations	106.6	149.3	42.8	
5	Fleet & Equipment	30.6	25.5	(5.1)	
6	Growth - Distribution System Reinforcement	52.6	54.9	2.3	
7	Real Estate & Workplace Services	118.7	52.1	(66.6)	
8	Technology Information Services (TIS)	39.4	63.7	24.3	
9	Transmission Pipe and Underground Storage	102.5	280.7	178.2	
10	Utilization	120.3	136.5	16.2	
11	Extended Alliance Fixed Overhead	21.3	21.7	0.3	
12	Capitalized Overheads	0.0	0.0	0.0	
13	Integration Capital	41.6	43.6	2.0	
14	Community Expansion	20.7	14.0	(6.8)	
15	Other	22.9	42.0	19.1	/u
16	Total	1,444.3	1,605.7	161.3	/u

Notes:
(1) Capital expenditures are shown on an annual basis
(2) Expenditures are net of contributions and include IDC

[42] EB-2020-0136.

a) Compression Stations: The increase of $151.5 million is primarily related to the construction of the Dawn to Corunna Replacement[43] Project. This is offset by the completion of the SCOR Meter Area Upgrade Phase 2 and a decrease in spend for major overhauls and strategic land purchases.
b) Customer Connections: Spend is forecasted to remain consistent between 2022 and 2023.
c) Distribution Pipe: The decrease of $196.6 million is primarily related to large projects executed in 2022 including: the NPS 20 Replacement Cherry to Bathurst[44]**,** St. Laurent Ottawa North Replacement Project [45], and Kirkland Lake Lateral Replacement. Spend in the Integrity Program increases overall due to the new Independent Asset Integrity Review (IAIR) Program and the TIMP Geohazard Mitigation Program. Lastly, there is an increase in spend for the Service Relay Program as a result of easing of work restrictions and an increase in relocation projects based on adjustments to regional forecasts.
d) Distribution Stations: The increase of $42.8 million is primarily related to the construction of several large Gate and Feed projects including Crowland Storage Transfer and Lisgar Station projects.
e) Fleet and Equipment: The decrease of $5.1 million is due to a decrease in the planned purchase of fleet vehicles due to delays in the supply chain and a decrease in the purchase of tools.
f) Growth: The increase of $2.3 million is due to a slight increase in reinforcement activity as a result of the growth forecast.
g) REWS: The decrease of $66.6 million is due to timing of anticipated land purchases such as the anticipated purchase of land to replace the Kelfield

[43] EB-2022-0086.
[44] EB-2020-0136.
[45] EB-2020-0293.

facility in 2022 and the development timing of large projects such as the new London Site in the City of London and interior renovations at 50 Keil Drive in the Municipality of Chatham.

h) TIS: The increase of $24.3 million is driven primarily by projects that are required to support processes and systems while in parallel reducing Enbridge Gas's operational and cybersecurity risks. Significant projects include the Contract Market Harmonization Project, Contract Market Systems – Technology Obsolescence and Gas Recovery Harmonization.

i) Transmission Pipe and Underground Storage: The increase of $178.2 million is primarily due to the construction of the Panhandle Regional Expansion Project[46], Leamington Interconnect and Crowland Wells Upgrade projects offset by a decrease in Transmission Integrity spend including the completion of the Dawn-Cuthbert 26, 34 and 42 inch retrofit projects.

j) Utilization: The increase of $16.2 million is due primarily to meter replacements in 2023 and increase in the cost to purchase meters. Due to supply chain constraints and a decrease in availability of diaphragm meters, Enbridge Gas is purchasing ultrasonic meters to supplement meter supply. This is slightly offset by reductions in regulator refits and meter installations due to Alliance partner resource constraints.

k) EA Fixed Overhead: No material variance.

l) Integration Capital**:** The increase in spend of $2 million is due to the completion of the AWS Phase 2, COG and Leak and Corrosion System Integration projects offset by AWS Phase 3 and construction costs related to the GTA West Site and GTA East Sites.

m) Community Expansion: The decrease of $6.8 million is driven by the completion of 2022 projects and the start of construction for 2023 projects

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[46] EB-2022-0157.

including Bobcaygeon Community Expansion Project[47] in the City of Kawartha Lakes, Eganville in the Townships of Bonnechere Valley and Admaston/Bromley, Burk's Falls in the Village of Burk's Falls, Perth East (Brunner) in the Township of Perth East, Kenora District (Highway 594) in the District of Kenora, Haldimand Shores Community Expansion Project[48] in the Township of Alnwick/Haldimand, Hidden Valley in the Township of Huntsville and Mohawks of the Bay of Quinte First Nation in Tyendinaga Mohawk Territory.

n) Other: The increase of $19.1 million is primarily due to customer driven RNG Injection Station projects. /u

4.5. 2024 Test Year vs 2023 Bridge Year

28. Table 11 provides a comparison of the 2024 Test Year compared to the 2023 Bridge Year. The 2024 Test Year includes all facility projects as identified in the AMP provided at Exhibit 2, Tab 6, Schedule 2, however Integrated Resource Planning (IRP) may impact the implementation of solutions and the timing of project execution. The 2024 Test Year expenditure of $1,491.3 million is $114.3 million /u lower than the 2023 Bridge Year Forecast of $1,605.7 million. This is primarily /u driven by the completion of significant projects including Panhandle Regional Expansion Project[49] and the Dawn to Corunna Replacement Project[50] partially offset by the St. Laurent Ottawa North Replacement Project. Variance explanations by asset class are provided below.

[47] EB-2022-0111.
[48] EB-2022-0088.
[49] EB-2022-0157.
[50] EB-2022-0086.

Table 11
Comparison of Utility Capital Expenditures 2023 Bridge Year & 2024 Test Year

Line No.	Particulars ($ millions)	2023 Bridge Year	2024 Test Year	2024 Test Over/(Under) 2023 Bridge	
		(a)	(b)	(c) = (b-a)	
1	Compression Stations	239.2	38.9	(200.3)	
2	Customer Connections	220.4	249.2	28.8	
3	Distribution Pipe	261.9	368.3	106.3	
4	Distribution Stations	149.3	120.6	(28.8)	
5	Fleet & Equipment	25.5	35.0	9.5	
6	Growth - Distribution System Reinforcement	54.9	105.1	50.2	
7	Real Estate & Workplace Services	52.1	56.6	4.5	
8	Technology Information Services (TIS)	63.7	112.4	48.7	
9	Transmission Pipe and Underground Storage	280.7	171.7	(109.0)	
10	Utilization	136.5	146.5	10.0	
11	Extended Alliance Fixed Overhead	21.7	21.9	0.3	
12	Capitalized Overheads	0.0	0.0	0.0	
13	Integration Capital	43.6	0.0	(43.6)	
14	Community Expansion	14.0	24.4	10.4	
15	Other	42.0	40.8	(1.2)	/u
16	Total	1,605.7	1,491.3	(114.3)	/u

Notes:
(1) Capital expenditures are shown on an annual basis
(2) Expenditures are net of contributions and include IDC

a) Compression Stations: The decrease of $200.3 million is primarily related to completion of the Dawn to Corunna Replacement[51] and Dawn to Corunna (Dawn Tie-In) projects in 2023. Significant projects in 2024 include the Dawn C Compression Lifecycle Project which is expected to be completed in 2026.

[51] EB-2022-0086.

b) Customer Connections: The increase of $28.8 million is related to the proposed harmonization of the Customer Connection Policy as provided at Exhibit 1, Tab 15, Schedule 1, Attachment 1.

c) Distribution Pipe: The increase of $106.3 million is primarily related to the construction of the St. Laurent Ottawa North Replacement Project, start of construction for the Wilson Avenue Replacement Project in the City of Toronto (expected completion in 2025) and the NPS 8 Port Stanley Replacement Project. There is also an increase in spend for the Service Relay Program offset by a decrease in relocation projects based on adjustments to the regional forecasts.

d) Distribution Stations: The decrease of $28.8 million is primarily related to the completion of the Crowland Storage Transfer and Lisgar Station projects in 2023, partially offset by smaller 2024 Gate, Feeder & A Station rebuilds.

e) Fleet and Equipment: The increase of $9.5 million is primarily due to an increase in vehicle purchases to meet Enbridge Gas's vehicle replacement strategy and limited purchases in 2023 due to supply chain issues.

f) Growth: The increase of $50.2 million is due primarily to the Kingston Creekford Road Reinforcement Project and the Wheatley 1B Panhandle Distribution Reinforcement projects. Other drivers include development spend to support the Hamilton Industrial Reinforcement Project which is expected to be completed in 2025 and the Enbridge Gas Distribution System Hydrogen Feasibility Study. All Reinforcement projects will be subject to the IRP Assessment Process. Additional details are provided at Appendix B-IPR of the AMP provided at Exhibit 2, Tab 6, Schedule 2.

g) REWS: The increase of $4.5 million is due to the timing of construction for new facilities including Kennedy Road Expansion in 2024, offset by Station B New Building and the SMOC/Coventry Facility Consolidation in 2023.

h) TIS: The increase of $48.7 million is driven primarily by projects that are required to support process and system enhancements while in parallel reducing Enbridge Gas's operational and cybersecurity risks. Significant projects include the Contract Market Harmonization Project, Contract Market Systems – Technology Obsolescence, General Service Rebasing Changes and Records Management Upgrade (2024 to 2026) projects.

i) TPUS: The decrease of $109 million is due primarily to the completion of the Panhandle Regional Expansion Project[52] offset by the expected start of construction for the Dawn Parkway Expansion Project (Hamilton Kirkwall) and Panhandle Line Replacement projects.

j) Utilization: The increase of $10 million is due primarily to the purchase of meters. Due to supply chain issues causing a decrease in availability of diaphragm meters, Enbridge Gas is purchasing ultrasonic meters to supplement meter supply.

k) Integration Capital: The decrease in spend of $43.6 million is due to the completion of integration programs. Projects expected to be completed in 2023 include Asset & Work Management (AWS) Phase 3, GTA West Site, GTA East Site and several other small TIS projects. The GTA West Site Project will dispose of the Brampton Colony Court, Burlington Mainway and Milton facilities and construct a new asset with an estimated in-service of 2023. The GTA East Site Project will dispose of the Coburg and Peterborough and construct a new consolidated facility with an estimated in-service of 2023. The facility projects are required as a result of boundary realignment in the existing EGD and Union rate zones to efficiently combine the operations teams.

[52] EB-2022-0157.

l) Community Expansion: The increase of $10.4 million is driven by the completion of 2023 projects and the construction of 2024 projects including Boblo Island in the town of Amherstburg, Neustadt in the Municipality of West Grey, St. Charles in the Municipality of St. Charles, Sudbury District, East Gwillimbury in the town of East Gwillimbury and Chute a Blondeau in the township of East Hawkesbury.

m) Other: The decrease of $1.2 million is primarily due to customer driven RNG injection projects. /u

CAPITAL UPDATE

DANIELLE DREVENY, MANAGER CAPITAL FINANCIAL PLANNING & ANALYSIS
BOB WELLINGTON, MANAGER ASSET MANAGEMENT GOVERNANCE AND RISK
JASON VINAGRE, MANAGER REGULATORY ACCOUNTING

1. Enbridge Gas filed this 2024 Rates Application and the majority of its supporting evidence on October 31, 2022 (October Filing) and the balance of its evidence on November 30th, 2022 (November Filing). On March 8, 2023, Enbridge Gas filed a limited update to its evidence (March Filing) which reflected updates and corrections to certain exhibits and interrogatory responses. The October Filing contained a large majority of the evidence in this proceeding. Included in the October filing were Enbridge Gas's, then current, capital budget forecasts for 2022 to 2024.

2. During the Technical Conference, Enbridge Gas indicated that it would report on any updates to the capital budgets set out in its pre-filed evidence stemming from its 2024 budgeting process as soon as that information could be provided and in advance of a hearing in this proceeding should a hearing occur[1].

3. Since the October Filing, Enbridge Gas has, in support of the ongoing development of its 2024 budget, prepared updated 2023 and 2024 capital forecasts which has resulted in changes to the planned capital expenditures set out in the pre-filed evidence. The purpose of this evidence (Capital Update) is to provide an update to the capital budget underpinning the March Filing and the subsequent impacts on rate base and revenue requirement.

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[1] 5 TC Tr. 10.

4. This evidence is organized as follows:
    1. Overview
    2. Capital Updates
    3. Depreciation Update
    4. PREP and D2C
    5. Revenue Requirement and Deficiency Impacts

1. Overview

5. This Capital Update reflects actual capital expenditures for 2022 and updates to Enbridge Gas's forecast capital expenditures for the 2023 Bridge Year and 2024 Test Year and the subsequent impacts on rate base for each of the aforementioned years.

6. The updates to the 2023 Bridge Year and 2024 Test Year capital expenditures and rate base amounts are current as of June 2023 and are now available pursuant to Enbridge Gas's 2024 capital budget process and timelines which commenced shortly after the Technical Conference in April 2023[2]. The updated 2023 and 2024 capital budgets were not confirmed until very recently, and Enbridge Gas has prepared and filed this evidence as soon as possible thereafter. As will be seen in the evidence, Enbridge Gas changed the timing for some large projects (including the Panhandle Regional Expansion Project (PREP). It would have left an incomplete picture to simply inform the OEB about major project timing changes without indicating all of the other changes seen in the 2023 and 2024 capital budgets.

[2] Enbridge Gas's budget process timing is described at Exhibit I.2.6-SEC-111.

7. During the Technical Conference, Enbridge Gas provided information in relation to planned 2023 capital projects that had been deferred or cancelled[3]. However, Enbridge Gas also indicated that while certain projects would not be undertaken in 2023, other projects had been moved or deferred from 2022 and 2023.[4]

8. In addition to reprioritizing the timing of capital projects, as part of this Capital Update, Enbridge Gas has also reflected certain cost pressures faced since the development of the budgets underpinning the March Filing, as well as the inclusion of new projects which were not budgeted for at the time. Note that while Enbridge Gas made limited updates in the March Filing, the underlying capital budgets date back to the October filing and were developed in or around mid 2022 (more than one year ago).

9. Also included in this Capital Update are certain adjustments to take into account special treatment for two large capital projects: PREP and the Dawn to Corunna Project (D2C).

10. Enbridge Gas is proposing a levelized approach to cost recovery for PREP. This approach will exclude in-service additions for the project from 2024 rate base. A separate unit rate, based on an average of the five-year net revenue requirement for the project, will instead be calculated and applied for cost recovery during the 2024 Test Year and each year of the incentive rate mechanism term. This Capital Update contains adjustments to capital expenditures and rate base to account for this approach.

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[3] JT5.02.
[4] 4 TC Tr. 216.

11. The allocation of costs to regulated and unregulated storage operations related to D2C has not yet been determined[5] and is an issue for Phase 2 of the rebasing proceeding. As such, Enbridge Gas recognizes that the rate impact of D2C is more appropriately determined in Phase 2. Consequently, this Capital Update contains adjustments to remove the cost consequences of D2C from the 2024 revenue requirement. Enbridge Gas will reflect the outcomes of any future determination on the allocation of D2C costs in final rates when the final rates for 2024 are set following Phase 2 of this proceeding.

12. Finally, this Capital Update incorporates revised depreciation rates. The revised depreciation rates address the inclusion of historical retirement data for Union assets that was not originally included in the Enbridge Gas Depreciation Study prepared by Concentric Energy Advisors (Concentric). The revised depreciation rates also incorporate a revised truncation date for a specific asset to address changes in retirement of that asset.

13. While the bulk of this update is focused on capital, the Capital Update also includes an adjustment to forecast expenditures for DSM to account for inflation impacts pursuant to the OEB's Decision in Enbridge Gas's application for a multi-year demand side management plan[6]**.** This update has been included to more accurately reflect the updated revenue deficiency.

14. Table 1 provides a summary and comparison of capital expenditures in the March Filing relative to this Capital Update.

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[5] EB-2022-0086, Decision and Order, p.9.
[6] EB-2021-0002, Decision and Order, p.5.

Table 1
Capital Expenditures

Line No.	Particulars ($ millions)	2022 Estimate/Actual	2023 Bridge Year	2024 Test Year
		(a)	(b)	(c)
1	March Filing	1,444.3	1,605.7	1,491.3
2	Capital Update	1,437.1	1,427.2	1,470.3
3	Increase/(Decrease)	(7.2)	(178.5)	(21.1)

Note: Expenditures are shown inclusive of IDC and overheads and net of contributions.

15. Table 2 provides a summary and comparison of utility rate base in the March Filing relative to this Capital Update.

Table 2
Rate Base

Line No.	Particulars ($ millions)	2022 Estimate/Actual	2023 Bridge Year	2024 Test Year
		(a)	(b)	(c)
1	March Filing	15,101.3	15,640.1	16,281.1
2	Capital Update	15,381.4	15,636.7	16,212.3
3	Increase/(Decrease)	280.1	(3.4)	(68.8)

16. Table 3 provides a summary the 2024 revenue deficiency impacts stemming from this Capital Update.

Table 3
Capital Update Revenue Deficiency Impacts

Line No.	Particulars ($ millions)	2024 Deficiency
1	March Filing Deficiency	(294.1)
2	Capital Updates	22.4
3	PREP – Remove 2024 revenue requirement impact	(14.4)
4	D2C – Remove 2024 revenue requirement impact	22.5
5	Depreciation Updates	3.1
6	DSM – Inflation update	(8.0)
8	Updated Deficiency	(268.5)

17. Detailed variance explanations of changes to capital expenditures and rate base are provided in Section 2. Details on the depreciation updates are provided in Section 3. A description of the proposed levelized approach to be applied to PREP and the treatment of D2C is provided in Section 4. Revenue requirement and deficiency impacts of this Capital Update are provided in Section 5.

2. Capital Updates

18. The following sections provide updates related to capital expenditures and rate base and variance explanations for the updates relative to the March Filing.

2.1 Capital Expenditures

19. The 2022 to 2024 updated capital expenditures are $206.8 million lower than the 2022 to 2024 capital expenditures in the March Filing largely due to the removal of PREP. Inclusive of PREP, capital expenditures are relatively flat over the 2022 to 2024 period when comparing the March Filing versus this Capital Update. Significant areas of change from 2022 to 2024 include:

- Integration Capital: updated to reflect the deferral of the GTA East and West facilities resulting in a decrease to 2023 integration spend of $29.9 million. The facilities are now expected to be completed in 2026.
- Facility Dispositions: As a result of the shift in timing for the GTA East and West integration projects, the forecasted disposition of buildings has been updated for 2024. The evidence in the March Filing included the forecasted disposition of 6 sites including 5 related to the GTA East and West projects[7] (Peterborough, Cobourg, Burlington, Milton, and Brampton). These facilities are now forecasted for disposition in 2027 after the completion of the GTA East and West projects. The Ottawa Depot (Coventry) site was also previously forecasted to be disposed in 2024; however, updated timing for the new South Merivale Operations Centre (SMOC)/Coventry facility consolidation project has shifted the disposition of SMOC to 2024 and the Ottawa Depot site to 2025. Note that SMOC was originally forecasted for disposition in 2023[8].
- D2C Project: The OEB granted Leave to Construct (LTC) approval for the project in November of 2022. Subsequent to LTC approval, Enbridge Gas received revised cost estimates for the project which resulted in an $88 million increase to the forecasted cost, primarily driven by inflationary pressures. In an effort to mitigate the cost pressures and keep the capital expenditures relatively stable to the previously filed evidence, Enbridge Gas has reprioritized capital spend over the 2023 to 2024 period to offset the incremental costs for the project.

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[7] Exhibit 1, Tab 9, Schedule 1, p.23.
[8] Exhibit 4, Tab 5, Schedule 1, p.14.

- Customer Connections: Customer connections costs have increased in both 2022 and 2023 related to an overall increase in forecasted new customer connections compounded with inflationary pressures in construction and material costs.
- Inflation and Increasing Complexity for Construction Projects: The March Filing did not include any provisions related to the rapid escalation of inflationary pressures in 2022. Inflationary cost pressures have had a significant impact on project estimates over the 2022 and 2023 periods. In addition, costs associated with an increasingly complex construction environment are also increasing. Examples of this include an increasing number of permits required by permitting agencies and additional work required under these permits, challenges obtaining timely locates and costs associated with dedicated locators in some regions, and legislated requirements for soil testing and the associated costs for storage, disposal and construction delays. All of these factors contribute to increasing costs relative to original project estimates.

20. Table 4 provides an overview of capital expenditures contained in the March Filing. Table 5 provides an overview of the updated capital expenditures forecast in this Capital Update.

Table 4
Utility Capital Expenditures by Asset Class
March Filing

Line No.	Particulars ($ millions)	Category	2022 Estimate	2023 Bridge Year	2024 Test Year	2022-2023 Variance	2023-2024 Variance
			(a)	(b)	(c)	(d)=(b-a)	(e)=(c-b)
1	Compression Stations	Storage	87.7	239.2	38.9	151.5	(200.3)
2	Customer Connections	Growth	220.7	220.4	249.2	(0.3)	28.8
3	Distribution Pipe	Dist Ops	458.5	261.9	368.3	(196.6)	106.3
4	Distribution Stations	Dist Ops	106.6	149.3	120.6	42.8	(28.8)
5	Fleet & Equipment	General	30.6	25.5	35.0	(5.1)	9.5
6	Growth - Distribution System Reinforcement	Growth	52.6	54.9	105.1	2.3	50.2
7	Real Estate & Workplace Services	General	118.7	52.1	56.6	(66.6)	4.5
8	Technology Information Services	General	39.4	63.7	112.4	24.3	48.7
9	Transmission Pipe and Underground Storage	Storage	102.5	280.7	171.7	178.2	(109.0)
10	Utilization	Dist Ops	120.3	136.5	146.5	16.2	10.0
11	Extended Alliance Fixed Overhead	Other	21.3	21.7	21.9	0.3	0.3
12	Integration Capital	Other	41.6	43.6	0.0	2.0	(43.6)
13	Community Expansion	Growth	20.7	14.0	24.4	(6.8)	10.4
14	Other	Other	22.9	42.0	40.8	19.1	(1.2)
15	Total		1,444.3	1,605.7	1,491.3	161.3	(114.3)

Notes:
(1) Expenditures are shown by asset class inclusive of IDC and overheads and net of contributions.
(2) Expenditures are shown on an annual basis.

Table 5
Utility Capital Expenditures by Asset Class
Capital Update

Line No.	Particulars ($ millions)	Category	2022 Actual	2023 Bridge Year	2024 Test Year	2022-2023 Variance	2023-2024 Variance
			(a)	(b)	(c)	(d)=(b-a)	(e)=(c-b)
1	Compression Stations	Storage	106.8	321.8	46.3	215.0	(275.5)
2	Customer Connections	Growth	297.0	286.3	304.1	(10.7)	17.8
3	Distribution Pipe	Dist Ops	477.5	237.5	357.1	(240.0)	119.6
4	Distribution Stations	Dist Ops	97.1	67.5	83.5	(29.7)	16.1
5	Fleet & Equipment	General	30.6	8.9	31.5	(21.7)	22.6
6	Growth - Distribution System Reinforcement	Growth	69.4	55.1	85.2	(14.3)	30.1
7	Real Estate & Workplace Services	General	64.4	63.0	63.0	(1.4)	0.0
8	Technology Information Services	General	28.1	47.1	102.4	19.1	55.3
9	Transmission Pipe and Underground Storage	Storage	96.8	79.0	69.2	(17.9)	(9.8)
10	Utilization	Dist Ops	98.4	160.7	152.3	62.3	(8.4)
11	Extended Alliance Fixed Overhead	Other	27.0	25.6	39.8	(1.5)	14.3
12	Integration Capital	Other	28.7	20.0	0.0	(8.7)	(20.0)
13	Community Expansion	Growth	14.2	20.6	11.2	6.4	(9.4)
14	Other	Other	1.1	34.3	124.6	33.1	90.3
15	Total		1,437.1	1,427.2	1,470.3	(9.9)	43.1

Notes:
(1) Expenditures are shown by asset class inclusive of IDC and overheads and net of contributions.
(2) Expenditures are shown on an annual basis.
(3) PREP capex reductions of $22.7M in 2023 and $194.9M in 2024.

Capital Expenditure Comparisons

21. The following sections provide detailed variance explanations between the capital expenditures in the March Filing compared to the Capital Update. Table 6 summarizes theses variances from 2022 to 2024.

Table 6
Utility Capital Expenditures by Asset Class
March Filing Versus Capital Update - Variance

Line No.	Particulars ($ millions)	Category	2022 Actual /Estimate	2023 Bridge Year	2024 Test Year
			(a)	(b)	(c)
1	Compression Stations	Storage	19.1	82.5	7.4
2	Customer Connections	Growth	76.3	65.9	54.9
3	Distribution Pipe	Dist Ops	19.0	(24.5)	(11.2)
4	Distribution Stations	Dist Ops	(9.4)	(81.9)	(37.0)
5	Fleet & Equipment	General	(0.1)	(16.7)	(3.5)
6	Growth - Distribution System Reinforcement	Growth	16.8	0.3	(19.9)
7	Real Estate & Workplace Services	General	(54.3)	10.9	6.4
8	Technology Information Services	General	(11.4)	(16.6)	(10.0)
9	Transmission Pipe and Underground Storage	Storage	(5.7)	(201.8)	(102.5)
10	Utilization	Dist Ops	(21.9)	24.2	5.9
11	Extended Alliance Fixed Overhead	Other	5.7	3.9	17.9
12	Integration Capital	Other	(12.9)	(23.7)	0.0
13	Community Expansion	Growth	(6.5)	6.6	(13.2)
14	Other	Other	(21.8)	(7.8)	83.8
15	Total		(7.2)	(178.5)	(21.1)

Notes:
(1) Expenditures are shown by asset class inclusive of IDC and overheads and net of contributions.
(2) Expenditures are shown on an annual basis.

2022 Actual (Capital Update) vs 2022 Estimate (March Filing)

22. The 2022 actual expenditure (Capital Update) of $1,437.1 million is $7.2 million lower than the 2022 Estimate (March Filing) of $1,444.3 million. There are several factors driving the variances in 2022 including the deferral of the St. Laurent project, increases to the Integrity and customer connections portfolios, and inflationary pressures on projects overall.

a) Compression Stations: The increase of $19.1 million is primarily related to the advance purchase of materials for the Dawn to Corunna Replacement[9] Project of $18.6 million, emergent cost pressures related to the Parkway C Gas Generator Midlife Overhaul of $6.4 million, offset by lower spend on the Corunna (SCOR) Meter Area Upgrade Phase 2 Project of $4.2 million.
b) Customer Connections: The increase of $76.3 million is due to an increase in the number of connections compared to the forecast and the actual costs required to connect customers being higher compared to the AMP budgeting process for this asset class sub-program.
c) Distribution Pipe: The increase of $19.0 million is due to an increase in work related to integrity of $66.8 million, relocations of $17.7 million and service relays of $10.7 million. The remaining variance is driven by main replacements including higher costs for Kirkland Lake of $8.1 million and for the London Lines Replacement Project[10] due to costs deferred from 2021 to 2022 of $6.9 million and other main replacement work of $30.5 million, offset by the deferral of the St. Laurent Ottawa North Replacement Project[11] to

[9] EB-2022-0086.
[10] EB-2020-0192.
[11] EB-2020-0136.

2024 of $79.0 million and the deferral of segments for the NPS 20 Replacement Cherry to Bathurst[12] project to 2023 of $44.9 million.

d) Distribution Stations: The decrease of $9.4 million is due to the deferral of work on Gate, Feeder and A Stations projects including Bayview Feeder and Albion Feeder

e) Fleet and Equipment: There are no significant variances related to the decrease in spend of $0.1 million.

f) Growth: The increase of $16.8 million is due to higher spend for the Greenstone Mine, Ingersoll Transmission, Byron Transmission, and Staples Reinforcement projects.

g) Real Estate and Workplace Services: The decrease of $54.3 million is due to the deferral of work on several projects including the SMOC/Coventry Facility Consolidation, Kennedy Rd Expansion, Brockville Operations Centre, Station B and Kelfield Operations Centre.

h) Technology Information Services: The decrease of $11.4 million is due to the deferral of projects including Green Button, Truck Modern Replacement and Content Management Enhancement.

i) Transmission Pipe and Underground Storage: The decrease of $5.7 million is due to lower spend on the Sarnia Industrial Line Project[13] and the Dawn to Cuthbert – NPS 42 Replacement project.

j) Utilization: The decrease of $21.9 million is due to supply chain constraints resulting in lower meter exchanges, lower meter and regulator refit purchases.

k) Extended Alliance Fixed Overhead: The increase of $5.7 million is due to an increase in costs and one-time fuel surcharges.

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[12] EB-2020-0136.
[13] EB-2019-0218.

l) Integration Capital: The decrease of $12.9 million is due to the deferral of the REWS GTA East and GTA West new sites of $11 million. The remaining variance of $1.9 million is due to adjustments in timing and spend for the TIS integration projects.
m) Community Expansion: The decrease of $6.5 million is due to shifts in timing for the execution of NGEP Phase 2 projects.
n) Other: The decrease of $21.8 million is due to the timing of execution of customer driven RNG projects.

2023 Bridge Year (Capital Update) vs 2023 Bridge Year (March Filing)

23. The 2023 Bridge Year (Capital Update) expenditure of $1,427.2 million is $178.5 million lower than the 2023 Bridge Year (March Filing) of $1,605.7 million. There are several factors driving the variances for 2023 including the deferral of the Panhandle Regional Expansion Project[14] to 2024, an increase in costs for the Dawn to Corunna Replacement Project[15] and a reprioritization of the portfolio to support increases to the integrity and customer connections portfolios and inflationary pressures on projects overall. Table 7 summarizes the variances by asset class and driver. Further explanations are also provided by asset class.

[14] EB-2022-0157.
[15] EB-2022-0086.

Table 7
Utility Capital Expenditures by Asset Class
March Filing Versus Capital Update

Line No.	Particulars ($ millions)	Category	2023 As Filed	Carry Forward From Prior Year (+)	New (+)	Cancelled /Deferred to Subsequent Year (-)	Other (+/-) (3)(4)	2023 Update
			(a)	(b)	(c)	(d)	(e)	(f)=(a+b+c+d+e)
1	Compression Stations	Storage	239.2	20.7	4.2	(18.8)	76.5	321.8
2	Customer Connections	Growth	220.4	0.0	0.0	0.0	65.8	286.3
3	Distribution Pipe	Dist Ops	261.9	36.4	23.6	(83.4)	(1.1)	237.5
4	Distribution Stations	Dist Ops	149.3	10.3	10.0	(58.6)	(43.5)	67.5
5	Fleet & Equipment	General	25.5	0.0	2.3	0.0	(18.9)	8.9
6	Growth - Distribution System Reinforcement	Growth	54.9	1.7	26.1	(14.3)	(13.5)	55.1
7	Real Estate & Workplace Services	General	52.1	0.5	2.5	(16.8)	24.7	63.0
8	Technology Information Services	General	63.7	1.3	2.4	(12.4)	(7.9)	47.1
9	Transmission Pipe and Underground Storage	Storage	280.7	39.9	4.4	(255.1)	9.1	79.0
10	Utilization	Dist Ops	136.5	0.0	0.0	0.0	24.2	160.7
11	Extended Alliance Fixed Overhead	Other	21.7	0.0	0.0	0.0	3.9	25.6
12	Integration Capital	Other	43.6	5.1	1.2	(29.9)	0.0	20.0
13	Community Expansion	Growth	14.0	0.0	0.0	0.0	6.6	20.6
14	Other	Other	42.0	0.0	0.0	(7.7)	0.0	34.3
15	Total		1,605.7	115.9	76.7	(497.0)	125.9	1,427.2

Notes:

(1) Expenditures are shown by asset class inclusive of IDC and overheads and net of contributions.

(2) Expenditures are shown on an annual basis.

(3) Includes changes in capex estimates, allocation of Overheads, profiling differences, etc.

(4) Panhandle Regional Expansion Project capex reductions of $22.7M in 2023.

a) Compression Stations: The increase of $82.5 million in compression stations is attributed to $16.4 million of delayed expenditures from 2022 for D2C compounded by a cost increase of $69.3 million for planned work 2023 for this project. This variance is further compounded by small carry over costs, increases to planned projects and costs associated with unplanned failures which are partially offset by $18.8 million in deferrals and decreases for several other smaller projects.
b) Customer Connections: The increase in $65.9 million is related to an overall increase in forecasted new customer connections compounded with inflationary pressures in construction and material costs.
c) Distribution Pipe: While there is an overall decrease of $24.5 million, cost pressures have been identified. These cost pressures include $30.8 million of 2022 carry over costs for KOL Cherry to Bathurst, $5.6 million in carry over costs for several smaller distribution pipe projects, $8.9 million worth of new pipeline replacement and class location projects, and $14.2 million in new integrity digs and exposed water way crossing replacements. These cost pressures have been offset through reprioritization of $84 million in integrity retrofits and depth of cover work, reductions to pipeline relocation blankets based on updated municipal construction plans, and reprioritization of main replacement and corrosion expenditures.
d) Distribution Stations: The decrease of $81.9 million is primarily related to $19.1 million for the delay of the Lisgar Gate station as the project is rescoped, $23.6 million for deferral of the Crowland station, and deferrals and reductions of $59.5 million in other smaller station projects during portfolio reprioritization which are partially offset by increases of $10.3 million in carry over costs from 2022 and $10 million in new station investments identified through inspections and equipment failures.

e) Fleet & Equipment: The decrease of $16.7 million is related to identification of $2.3 million in requirements for new tools and equipment offset by savings of $18.9 million from reprioritization for vehicles and equipment purchases.
f) Growth: While there have been $26.1 million in new growth projects identified in 2023, these have been offset by equivalent savings from things such as deferral and downsizing of planned growth projects following review of specific customer connection projects and resultant system constraints. As a result, there is a small variance.
g) Real Estate and Workplace Services: The increase of $10.9 million is primarily related to a $22.1 million increase for the SMOC/Coventry (Ottawa Building) Facility project driven by a change to timing for the project. This increase has been partially offset by a $12 million reduction to the new Station B building through adjusted pacing of construction and other minor reductions to the forecast.
h) Technology Information Services: The decrease of $16.6 million is related to reprioritization of the TIS Business Solutions portfolio based on business needs resulting in $20.3 million in reductions and deferrals partially offset by $3.5 million in carry over costs and new investments.
i) Transmission Pipe and Underground Storage: The decrease of $201.8 million is related to deferral of $223.5 million for PREP, deferral of $8.9 million for the Crowland Wells Upgrade project, and several other small projects that were reduced or saw changes to forecast during updated forecasting and reprioritization of the portfolio amounting to an additional $13.9 million reduction. These reductions were offset by $38.9 million in 2022 materials costs for the Panhandle Regional Expansion projects and $4.5 million from other smaller projects being carried into 2023, and minor increases to the Integrity Management Program resulting primarily from work

carrying over from prior years and an increase to planned digs compounded with inflationary pressures.

j) Utilization: The increase of $24.2 million is primarily a result of $5.5 million costs for delayed meters ordered for 2022, an increase of $15.1 million for meters ordered for receipt in 2023 to build inventory for increased customer connections and meter exchange activity, a $2.3 million increase in regulators and meter exchange labour costs, associated with a moderate increase in planned work to catch up on work not complete in 2022, and some other minor increases in the portfolio.
k) EA Fixed Overhead: The increase of $3.9 million is related to the inclusion of third party pre-work blankets in the EA Fixed Overhead asset class.
l) Integration Capital: The decrease of $23.7 million is due to the deferral of the GTA East and GTA West REWS projects totalling $29.9 million offset by carry forward spend from 2022 for TIS integration projects totalling $6.3 million.
m) Community Expansion: The increase of $6.6 million is due to shifts in timing for the execution of NGEP Phase 2 projects.
n) Other: The decrease of $7.8 million is due to the deferral of customer driven RNG projects to 2024.

2024 Test Year (Capital Update) vs 2024 Test Year (March Filing)

24. The 2024 Test Year (Capital Update) expenditure of $1,470.3 million is $21.1 million lower than the 2024 Bridge Year (March Filing) of $1,491.3 million. There are several factors driving the variances including a reprioritization of the portfolio to support increases to the integrity and customer connections portfolios and inflationary pressures on projects overall. Note that the capital expenditures related

to PREP[16] has been removed from the Capital Update as Enbridge Gas is proposing a levelized approach to the impacts of shifting this project to 2024. Table 8 summarizes the variances by asset class and driver. Further explanations are also provided by asset class.

[16] EB-2022-0157.

Table 8
Utility Capital Expenditures by Asset Class
March Filing Versus Capital Update

Line No.	Particulars ($ millions)	Category	2024 As Filed	Carry Forward From Prior Year (+)	New (+)	Cancelled /Deferred to Subsequent Year (-)	Other (+/-) (3)(4)	2024 Update
			(a)	(b)	(c)	(d)	(e)	(f)=(a+b+c+d+e)
1	Compression Stations	Storage	38.9	10.7	15.1	(24.7)	6.3	46.3
2	Customer Connections	Growth	249.2	0.0	0.0	0.0	54.9	304.1
3	Distribution Pipe	Dist Ops	368.3	4.2	4.0	(97.8)	78.4	357.1
4	Distribution Stations	Dist Ops	120.6	8.1	5.6	(80.5)	29.7	83.5
5	Fleet & Equipment	General	35.0	1.3	2.6	0.0	(7.4)	31.5
6	Growth - Distribution System Reinforcement	Growth	105.1	15.2	9.3	(64.6)	20.2	85.2
7	Real Estate & Workplace Services	General	56.6	8.8	1.1	(34.6)	31.1	63.0
8	Technology Information Services	General	112.4	0.8	14.7	(13.9)	(11.6)	102.4
9	Transmission Pipe and Underground Storage	Storage	171.7	5.8	11.8	(39.0)	(81.1)	69.2
10	Utilization	Dist Ops	146.5	0.0	0.0	0.0	5.9	152.3
11	Extended Alliance Fixed Overhead	Other	21.9	0.0	0.0	0.0	17.9	39.8
12	Integration Capital	Other	0.0	0.0	0.0	0.0	0.0	0.0
13	Community Expansion	Growth	24.4	0.0	0.0	(13.2)	0.0	11.2
14	Other	Other	40.8	24.1	59.7	0.0	0.0	124.6
15	Total		1,491.3	79.0	123.9	(368.3)	144.3	1,470.3

Notes:

(1) Expenditures are shown by asset class inclusive of IDC and overheads and net of contributions.

(2) Expenditures are shown on an annual basis.

(3) Includes changes in capex estimates, allocation of Overheads, profiling differences, etc.

(4) Panhandle Regional Expansion Project capex reductions of $194.9M in 2024.

a) Compression Stations: The increase of $7.4 million is predominantly attributable to $7.4 million of work expected to carry forward for 2023 from the Dawn to Corunna project in addition to $2.1 million of smaller projects with forecasted carry-over costs, $7.6 million for an unplanned compressor overhaul and foundation replacement at the Hagar LNG station, $8.5 million in new projects identified though inspection activities and failures, and approximately $5.9 million worth of projects whose costs estimates have increased through project development from 2023 and prior years into 2024 which have added new cost pressures. These have been offset by approximately $24.7 million in project cancellations and deferrals, the most significant of which is the deferral of $16 million for the Dawn C Compression Lifecycle project to allow time for completion of the reliability assessment to inform the updated scope.
b) Customer Connections: The increase of $54.9 million is related to an increase in new customer connections compounded with inflationary pressures in construction and material costs.
c) Distribution Pipe: The decrease of $11.2 million is primarily attributed to deferral of $36.1 million for the Wilson Avenue project and $18.5 million for the Port Stanley replacement projects to provide sufficient time for further inspection and health assessment as part of the Enhanced Distribution Integrity Management program before finalizing the need and scope for these projects. Additionally, $20.4 million in planned integrity retrofit costs and $22.8 million of other small main replacements and relocations have been deferred. This is partially offset by a $48.1 million increase in integrity digs and $30.3 million in changes to other project estimates in addition to $4.2 million in smaller projects forecasted to carry costs into 2024 from 2023,

and $4.0 million in new main and bridge crossing replacement projects identified through inspections and surveys.

d) Distribution Stations: The decrease of $37.0 million is attributable to $80.5 million in deferral of smaller station projects during portfolio reprioritization. This is partially offset by $8.1 million in forecasted carry over costs from 2023 into 2024, $5.6 million in new station projects having been identified through inspections, and $29.7 million in cost increases on smaller station projects relating to increasing construction and material costs compared to the original estimates.

e) Fleet & Equipment: The decrease of $3.5 million is related to $2.2 million in anticipated carry over costs and new equipment and tool investments offset by reductions during reprioritization for vehicles and equipment purchases.

f) Growth: The decrease of $19.9 million is primarily due to the deferral of $24.1 million for the East Kingston Creekford Road Reinforcement through an interim solution using of CNG to support system peak demands, cancellation of $19.9 million for the Wheatley 1B Panhandle Distribution Reinforcement as locations for greenhouse expansion in Essex County have become clearer, and deferral of several smaller growth reinforcement projects. These reductions are partially offset by $15.2 million in forecasted carry-over costs from 2023, and $9.3 million of new reinforcement projects identified following review of specific customer connection projects and resultant system constraints.

g) Real Estate and Workplace Services: The increase of $6.4 million is primarily related to $14.1 million of cost increase for Station B attributable to inflationary pressures and execution timing, $13.3 million of deferred cost and inflationary pressures associated with the Ottawa building construction, and $3.7 million in smaller project increases; $8.8 million of project costs planned for prior years carrying into 2024 due to shifts in construction pacing and addition of several other smaller projects offset by a $25.2 million deferral of the Kennedy Rd land purchase and $9.4 million worth of several other small reductions and deferrals relating to reprioritization of projects and forecast refinements.

h) Technology Information Services: The decrease of $10.0 million is related to reprioritization of the TIS Business Solutions portfolio based on business needs leading to $11.6 million in reductions and $13.9 million in deferrals offset by $14.7 million in new investments added to the forecast and some minor carry over costs.

i) Transmission Pipe and Underground Storage: The decrease of $102.5 million is primarily a result of removal of $66.9 million from the forecast for PREP, deferral of $23.1 million for the Dawn to Parkway Expansion Project: Kirkwall to Hamilton Loop based on updated market forecasts, and delayed expenditures amounting to $29.7 million for the Panhandle Line Replacement. This is offset by a $11.2 million increase to integrity management primarily driven by an increase to expected number of digs compounded by inflationary pressures, and other smaller project increases determined through cost refinement.

j) Utilization: The increase of $5.9 million is primarily a result of an increase in meter orders to ensure sufficient inventory for the increase in forecasted customer connections and meter exchanges.

k) EA Fixed Overhead: The increase of $17.9 million is related is related to renegotiation of the Extended Alliance Contracts. Enbridge Gas recently completed a competitive RFP for construction services which provided the opportunity to review the total cost structure of their service model and propose new contract terms for the future 5 years. Previous contracts have mitigated inflationary impacts. However, the current market conditions have driven higher inflationary increases to fixed overheads which include labour rates, fuel costs, facility and maintenance costs. Select contracts had a provision for limited inflationary adjustment that was below market inflation. Other impacts to fixed overheads include but are not limited to business to business systems alignment, harmonization of policies and procedures, changing service providers in two regions (Northeast & GTA East), and increased capital investment costs. Additionally, the cost structure proposed in the new contract realigned the allocation of unit rates and fixed overhead which resulted in an overall construction cost below inflation.

l) Integration Capital: There are no integration capital projects after December 2023.

m) Community Expansion: The decrease of $13.2 million is due to shifts in timing for the execution of NGEP Phase 2 projects.

n) Other: The increase of $83.8 million is due to the carry forward of several customer-driven RNG projects from 2023 into 2024 totalling $24.1 million and the addition of several new customer driven CNG and RNG projects in 2024 totalling $59.7 million.

2.2 Rate Base

25. Table 9 provides an overview of rate base contained in the March Filing. Table 10 provides an overview of the updated rate base.

Table 9
Comparison of Utility Rate Base
March Filing

Line No.	Particulars ($ millions)	2022 Estimate	2023 Bridge Year	2024 Test Year	2022-2023 Variance	2023-2024 Variance
		(a)	(b)	(c)	(d)=(b-a)	(e)=(c-b)
	Property, Plant and Equipment					
1	Gross Property, Plant and Equipment	22,663.3	23,874.8	24,902.9	1,211.5	1,028.1
2	Accumulated Depreciation	(8,417.8)	(8,924.1)	(9,178.9)	(506.3)	(254.8)
3	Net Property, Plant and Equipment (1)	14,245.4	14,950.7	15,724.0	705.2	773.3
	Allowance for Working Capital					
4	Total Allowance for Working Capital	855.9	689.4	557.0	(166.5)	(132.4)
5	Total Utility Rate Base	15,101.3	15,640.1	16,281.1	538.7	640.9

Note:
(1) 2023 Bridge Year forecast of net property, plant and equipment includes $73.7 million related to Dawn to Corunna.
2024 Test Year Forecast of net property, plant and equipment includes $237.2 million related to Dawn to Corunna.

Table 10
Comparison of Utility Rate Base
Capital Update

Line No.	Particulars ($ millions)	2022 Actual	2023 Bridge Year	2024 Test Year	2022-2023 Variance	2023-2024 Variance
		(a)	(b)	(c)	(d)=(b-a)	(e)=(c-b)
	Property, Plant and Equipment					
1	Gross Property, Plant and Equipment	22,585.9	23,716.5	24,736.3	1,130.6	1,019.8
2	Accumulated Depreciation	(8,320.1)	(8,769.2)	(9,081.0)	(449.1)	(311.8)
3	Net Property, Plant and Equipment (1)	14,265.9	14,947.3	15,655.3	681.5	708.0
	Allowance for Working Capital					
4	Total Allowance for Working Capital	1,115.5	689.4	557.0	(426.1)	(132.4)
5	Total Utility Rate Base	15,381.4	15,636.7	16,212.3	255.4	575.6

Note:
(1) 2023 Bridge Year forecast of net property, plant and equipment includes $66.9 million related to Dawn to Corunna.
2024 Test Year Forecast of net property, plant and equipment includes $343.0 million related to Dawn to Corunna.

Rate Base Comparisons

26. The following sections provide detailed variance explanations between the rate base values in the March Filing compared to the Capital Update. Table 11 summarizes theses variances from 2022 to 2024.

Table 11
Comparison of Utility Rate Base
March Filing Versus Capital Update - Variance

Line No.	Particulars ($ millions)	2022 Actual /Estimate	2023 Bridge Year	2024 Test Year
		(a)	(b)	(c)
	Property, Plant and Equipment			
1	Gross Property, Plant and Equipment	(77.4)	(158.3)	(166.6)
2	Accumulated Depreciation	97.7	154.9	97.9
3	Net Property, Plant and Equipment	20.3	(3.4)	(68.7)
	Allowance for Working Capital			
4	Total Allowance for Working Capital	259.6	0.0	0.0
5	Total Utility Rate Base	280.1	(3.4)	(68.8)

2022 Actual (Capital Update) vs 2022 Bridge Year (March Filing)

27. 2022 Rate base increased by $280.1 million compared to the March Filing. This increase was primarily attributable to a $259.6 million increase in working capital primarily related to a higher average Gas in Storage balance resulting from a higher average reference price during 2022. A further increase of $20.3 million is attributable to lower actual depreciation in 2022 partially offset by lower in-service additions.

2023 Bridge Year (Capital Update) vs 2023 Bridge Year (March Filing)

28. 2023 Bridge Year Rate Base forecast to decrease by $3.4 million. The decrease is attributable to the impact of incorporating ending 2022 Actuals as 2023 opening balances, as well as a decrease in forecast in-service additions applicable to the removal of PREP partially offset by 2023 capital plan updates as noted above.

Offsetting these are the impacts of a higher forecast of net cost of retirements in 2023 and lower forecast depreciation.

2024 Test Year (Capital Update) vs 2024 Test Year (March Filing)

29. 2024 Test Year Rate Base is forecast to decrease by $68.8 million. The decrease is primarily attributable to the removal of PREP from the 2023 and 2024 capital forecasts, partially offset by changes to the forecast capital plan and expenditures as noted in Section 2.1 above.

Impact of 2022 Actuals and 2023/2024 Budget Updates

30. Incorporating the 2022 Actuals and 2023 Bridge Year forecast updates has resulted in a $2.4 million increase in opening 2024 net book value for property, plant and equipment (from $15,693.8 million to $15,696.2 million). The increase is attributable to lower depreciation and higher net cost of retirements, partially offset by a reduction to in-service additions between 2022 Actuals and 2023 Forecast. Flowing the 2022 Actuals and 2023 Bridge Year forecast updates through 2024 along with updates to 2024 Test Year forecast results in a decrease of the 2024 Test Year ending net book value of $209.7 million from $16,255.7 million to $16,145.4 million.

31. Applying the above impacts between 2022 Actuals and 2023/2024 forecast updates through the 2024 Test Year results in a decrease in Rate Base for 2024 of $68.8 million from $16,281.1 million to $16,212.3 million.

3. <u>Depreciation Update</u>

32. Enbridge Gas is including an update to the depreciation rates included in the Enbridge Gas Depreciation Study (Depreciation Study) as prepared by Concentric Energy Advisors, ULC (Concentric) for the Capital Update. The revised rates

address concerns raised in Exhibit 1.4.5-Staff-178 parts b) and c) regarding missing retirement data from 1997 to 2010 for Union assets. Enbridge Gas confirmed in its response that at the time of the study, Concentric did not have the historical Union retirement transactions for any years prior to 2010. The data was subsequently provided to Concentric and the revised depreciation rate calculations yielded an estimated increase to depreciation expense of $3.7 million, as confirmed on Day 4 of the Technical Conference[17]. This impact has subsequently been updated to $4.3 million based on this Capital Update.

33. Enbridge Gas is also proposing a revised depreciation rate for account 472.35 (Mainway). The Depreciation Study initially proposed a truncation date of 2023 for the Mainway asset as it was expected to be retired as part of the facility consolidation for the new Greater Toronto Area (GTA) West site. The forecasted retirement date was updated to 2024 as part of the budget process which resulted in a depreciation expense of $9.1 million based on the proposed rate of 50.48% included in the 2024 Test Year depreciation expense as filed in the March 8, 2023 update. Construction of the GTA East and West sites, which were included in the Utility Integration Evidence at Exhibit 1, Tab 9, Schedule 1 page 33, have been paused. Enbridge Gas is re-evaluating the costs and timing of the GTA East and West projects due to delays to the construction schedules and a forecasted increase in the construction costs for the facilities. The revised truncation date for the Mainway asset is 2027. The depreciation rate has been updated to 14.21% and the revised depreciation expense for the 2024 Test Year is $2.6 million. The GTA East and West projects have been included in the AMP update with expected completion and in-service in 2026. The revised depreciation rates are provided at Attachment 1.

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[17] 4 TC Tr. 45.

4. PREP and D2C

34. As noted above, Enbridge Gas is proposing an alternative treatment for cost recovery of PREP and that D2C be moved to Phase 2 of this proceeding. The sections below provide details on these treatments for each project respectively.

4.1 PREP

35. This Capital Update has been adjusted to exclude forecast expenditures and 2024 in-service additions in relation to PREP. Enbridge Gas is proposing a separate levelized recovery mechanism for the project.

36. PREP is a large project ($358.0 inclusive of overheads) that is required to serve increasing demands in the Panhandle Market and is subject to leave-to-construct (LTC) approval[18] application. As noted in the updated LTC application, the proposed project consists of pipeline facilities and stations work forecast to close into service in 2024, and yard facilities that are forecast to close into service in 2025.

37. Recognizing that PREP has yet to receive LTC approval, Enbridge Gas believes that separate treatment of the project is warranted. As a result, Enbridge Gas proposes to exclude the costs and incremental revenues, that are attributable to the project's forecast 2024 in-service component, from the determination of the base 2024 cost of service revenue requirement. In this way, if forecast timing or costs are altered, or if OEB approval is not granted, then no adjustment to base rates or revenue requirement will be necessary. Subject to OEB approval of the PREP LTC application, Enbridge Gas proposes to separately calculate the forecast net

[18] EB-2022-0157.

revenue requirement of the project for the 2024 Test Year and each year of the IR term (2025 – 2028), for inclusion into rates in a levelized manner.

38. This proposal is similar to how approved ICM projects were handled over the deferred rebasing term. A separate unit rate will be calculated, based on the average of the five year net revenue requirement for the project, which would be implemented in the 2024 Test Year and remain fixed and in place for the duration of the IR term (or for the remainder of the term following OEB approval). The average unit rate would eliminate the rate fluctuations that would occur if the project's annual revenue requirement was treated as a y-factor each year (i.e. the revenue requirement would be negative in year 1 due to the partial rate base effectivity and income tax benefit provided by capital cost allowance, followed positive cost impacts in each of the following years of the IR term).

39. Also, similar to the treatment of prior ICM projects (and the proposed prospective treatment of future ICM projects), Enbridge Gas proposes to establish an associated variance account, the PREP Variance Account (PREPVA), that would capture any variance between the project's actual net revenue requirement and the actual revenues collected through the average unit rate that would be in place over the IR term. The variance account would ensure ratepayers do not over or under pay for the project, and that Enbridge Gas does not over or under recover over the IR term. The clearance of any cumulative balance in the account is proposed to occur at the end of the IR term, as during the IR term the account will be expected to capture the temporary differences between the average annual revenue requirement and the actual annual revenue requirement. Establishing an average unit rate at the outset of the IR term will be administratively efficient, as the project costs will not need to be reviewed annually as part of the annual price cap applications. Attachment 2 contains a draft accounting order for the PREPVA.

40. The annual forecast of costs, incremental revenues, and resulting revenue requirement attributable to the PREP 2024 in-service additions are provided in Attachment 2. The project's forecast revenue requirement includes carrying charges (costs of capital) and depreciation attributable to the $251.5 million capital addition forecast to occur in November 2024, as well as incremental operation and maintenance, property tax, and income tax amounts, partially offset by transmission margin revenue associated with incremental demands served by the project. Attachment 2 also provides the forecast average annual net revenue requirement for the project, of $7.3 million which the Company is proposing to derive a separate unit rate for inclusion in rates for the duration of the 2024 – 2028 IR term. The unit rates will be filed with the OEB with the Draft Rate Order for this proceeding.

41. Enbridge Gas notes that under its proposal, PREP capital costs associated with the yard facilities, which are forecast to be placed into service in 2025, will be recovered through the Company's proposed 2025 through 2028 price cap mechanism (i.e. through base rate price cap escalation or through the ICM mechanism), and are therefore not included in the proposed levelized recovery mechanism.

42. As part of the proposal for the separate treatment for the recovery of the revenue requirement related to the 2024 PREP in-service additions, the segregated PREP costs (including rate base, depreciation, and revenue requirement amounts) and associated unit rate would be excluded from the annual ICM threshold calculations and price cap escalations. Enbridge Gas's proposal, inclusive of the proposed variance account will ensure that only actual project costs are recovered, thus associated revenues will not be able to support additional capital spending (i.e.

through the ICM mechanism).

43. Attachment 5, page 3, provides details of the 2024 Test Year revenue deficiency excluding forecasted PREP costs but including the impact of the proposed levelized approach.

4.2 D2C

44. Enbridge Gas proposes that the determination of rate base treatment for D2C be deferred to Phase 2 of this proceeding. In its LTC Decision for D2C, the OEB approved the D2C project indicated that it was not making any decision on whether any part of the project cost is appropriate for inclusion in rate base. The OEB indicated the following:

> The OEB is of the view that the concerns raised by Pollution Probe and Energy Probe regarding the need for an examination of the overall integration of storage assets between the legacy storage of Enbridge Gas Distribution and Union Gas Limited is best addressed in the upcoming Enbridge Gas rebasing proceeding.
>
> The rebasing proceeding will address the appropriate allocation of storage and storage related costs to each of the regulated business and the unregulated business and, if Enbridge Gas seeks to put the Project into rate base, the extent to which the recovery of the cost of the Project from ratepayers is appropriate.[19]

45. Given that issues related to allocation of costs between Enbridge Gas's regulated and unregulated operations are being addressed in Phase 2 of this proceeding, Enbridge Gas believes that it is appropriate to consider the inclusion of the D2C

[19] EB-2022-0086, Decision and Order, November 3, 2022, p.9.

project in 2024 rate base at that time, including the questions of the amount of the costs (which are higher than forecast) and the allocation of the costs between regulated and unregulated operations. The use of interim rates in relation to implementation of Phase 1 determinations will allow the full approved rate base and revenue requirement implications of the D2C project determination in Phase 2 to be reflected in the final approved 2024 rate base and revenue requirement.

46. Enbridge Gas is therefore treating the 2024 revenue requirement associated with the D2C project separately in this Capital Update. The impact of D2C on the 2024 revenue requirement has been reflected as a reduction to the revenue deficiency. Attachment 3 provides details on the calculation of the 2024 revenue requirement for D2C.

47. Attachment 5, page 3, provides details of the 2024 Test Year revenue deficiency net of the impact of D2C.

5. Revenue Requirement and Deficiency Impacts

48. Taking into account each of the updates outlined above, the impact on the 2024 Test Year revenue requirement and related deficiency are summarized in Table 12 below.

Table 12
Changes to 2024 Test Year Deficiency

Line No.	Deficiency	Update		Impact ($ millions)
1	Deficiency – March Filing			(294.1)
		Capital Updates		
2		1.	Incorporate impact of 2022 Actuals and changes to 2023/2024 Capital Expenditures and In-service additions (1)	22.4
3		2.	Depreciation Rate update (2)	3.1
		PREP		
5		3.	Remove 2024 Revenue Requirement impacts (3)	(14.4)
		DSM		
6		4.	Reflect 2024 Inflation rate update	(8.0)
7	Subtotal – Deficiency Updated			(291.0)
8	Deficiency – Dawn to Corunna	Remove Dawn to Corunna Deficiency (4)		22.5
9	Deficiency – Capital Update	Base Deficiency net of Dawn to Corunna		(268.5)

Notes:
(1) Inclusive of PREP and associated updates. Reflects depreciation rates as proposed in Table 1 of Exhibit 4, Tab 5, Schedule 1, Attachment 1.
(2) Reflects updated depreciation rates set out in Attachment 1.
(3) Removal of revenue requirement impacts for PREP including rate base, depreciation, property taxes and O&M
(4) The impacts approved in Phase 2 will be reflected in the final deficiency for 2024.

49. The changes in revenue requirement and deficiency are explained in Table 13.

Table 13
Description of 2024 Test Year Revenue Requirement Changes and Impacts

Line No.		Update Item	Update Description	2024 Test Year Revenue Requirement Impact ($ millions)
	Capital Updates			
1	i)	Changes to 2023/2024 Capital Expenditures and In-service additions	Reflects actual capital expenditures for 2022 and changes in Enbridge Gas's forecast capital expenditures for the 2023 Bridge Year and 2024 Test Year and the subsequent impacts on rate base, depreciation and associated income tax implications to the 2024 Test Year revenue requirement.	22.4
2	ii)	Depreciation Rate Update	Update to the depreciation rates included in the Enbridge Gas Depreciation Study as prepared by Concentric for the Capital Update (see above for further details).	3.1
	PREP			
3	iii)	Remove 2024 Revenue Requirement	The Panhandle Regional Expansion Project has been removed from the 2024 Test Year base revenue requirement which include the impacts of capital expenditures forecast as part of in-service additions, resulting rate base and depreciation impacts, as well as applicable O&M and Municipal Property Taxes and associated income taxes.	(14.4)
	DSM			
4	iv)	Reflect 2024 Inflation rate update	The March Filing for 2024 DSM reflected a 2.0% assumed inflation rate. This update applies to the 2024 forecast DSM expenditures an updated inflation rate of 6.8% resulting in an increase of $8.0 million.	(8.0)

50. The impact on cost of capital, the revenue requirement and the deficiency are more fully detailed in Attachment 4 and Attachment 5. Attachment 4 provides a comparison of utility operating costs as between the March Filing and this Capital

Update. Attachment 5 provides updated cost of capital parameters, the updated required rate of return, updated utility income and updated deficiency calculations for the 2024 Test Year.

TABLE 1. ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO PLANT IN SERVICE AT DECEMBER 31, 2021
Related to Total Expense

Account	Description	Truncation Date	Estimated Survivor Curve	Net Salvage Percent	Surviving Original Cost as of 12/31/2021	Book Reserve	Future Accruals	Annual Accrual Amount	Composite Remaining Life	Annual Accrual Rate
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
LOCAL STORAGE PLANT										
442.00	STRUCTURES AND IMPROVEMENTS	0	40-S5	0%	6,282,181	2,805,060	3,477,121	105,928	24.7	1.69%
443.01	HOLDER - STORAGE TANK	0	45-R4	0%	5,804,412	4,023,544	1,780,869	55,594	19.1	0.96%
443.02	HOLDER EQUIPMENT	0	55-R4	0%	21,554,522	11,363,396	10,191,126	229,183	36.8	1.06%
TOTAL LOCAL STORAGE PLANT					**33,641,115**	**18,192,000**	**15,449,115**	**390,705**		1.16%
UNDERGROUND STORAGE PLANT										
451.00	LAND RIGHTS INTANGIBLE	0	55-R4	0%	74,762,354	45,841,825	28,920,529	1,102,904	23.0	1.48%
452.00	STRUCTURES AND IMPROVEMENTS	0	45-R3	-10%	104,433,820	47,148,032	67,729,170	2,964,640	23.7	2.84%
453.00	WELLS	0	45-R2.5	-30%	143,144,395	50,040,540	136,047,173	5,515,551	25.9	3.85%
454.00	WELL EQUIPMENT	0	40-R2	0%	13,364,517	8,575,936	4,788,581	175,831	21.4	1.32%
455.00	FIELD LINES	0	55-R3	-8%	201,920,080	53,298,115	164,775,572	5,130,627	33.4	2.54%
456.00	COMPRESSOR EQUIPMENT	0	40-R4	-6%	682,328,757	228,311,196	494,957,286	19,661,453	25.5	2.88%
457.00	REGULATING AND MEASURING EQUIPMENT	0	35-R3	-14%	77,194,133	51,829,828	36,171,484	2,003,634	15.6	2.60%
TOTAL UNDERGROUND STORAGE PLANT					**1,297,148,055**	**485,045,470**	**933,389,796**	**36,554,640**		2.82%
TRANSMISSION PLANT										
461.00	LAND RIGHTS INTANGIBLE	0	60-R4	0%	88,171,402	20,599,533	67,571,869	1,507,598	44.3	1.71%
462.00	COMPRESSOR STRUCTURES AND IMPROVEMENTS	0	50-S4	-5%	163,351,958	40,353,631	131,165,925	3,377,914	37.7	2.07%
463.00	MEASURING AND REGULATING STRUCTURES AND IMPROVEMENTS	0	55-S4	-6%	11,252,284	7,167,268	4,760,153	157,646	26.2	1.40%
464.00	EQUIPMENT	0	30-L0.5	-5%	2,920,218	523,642	2,542,587	160,081	15.8	5.48%
465.00	MAINS	0	60-R4	-12%	2,783,251,797	919,330,147	2,197,911,866	49,201,674	42.3	1.77%
466.00	COMPRESSOR EQUIPMENT	0	30-R4	-7%	1,005,060,039	331,530,582	743,883,660	37,417,456	19.6	3.72%
467.00	MEASURING AND REGULATING EQUIPMENT	0	40-R4	-15%	395,646,542	119,798,512	335,195,011	12,112,032	27.7	3.06%
TOTAL TRANSMISSION PLANT					**4,449,654,239**	**1,439,303,314**	**3,483,031,070**	**103,934,401**		2.34%
DISTRIBUTION PLANT										
471.00	LAND RIGHTS INTANGIBLE	0	60-R4	0%	63,907,560	12,099,619	51,807,941	1,150,753	45.2	1.80%
472.00 *	STRUCTURES AND IMPROVEMENTS - OTHER	0	40-S0.5	0%	220,832,605	64,014,227	156,818,378	7,005,487	21.7	3.17%
472.31	STRUCTURES AND IMPROVEMENTS - STONEY CREEK	2046	40-S0.5	0%	29,662,115	5,056,171	24,605,944	1,325,428	18.6	4.47%
472.32	STRUCTURES AND IMPROVEMENTS - WIN-RHODES	2046	40-S0.5	0%	23,216,546	5,549,955	17,666,591	991,735	17.9	4.27%
472.33	STRUCTURES AND IMPROVEMENTS - LONDON ADMIN	2026	40-S0.5	0%	19,789,902	9,778,917	10,010,985	2,365,393	4.2	11.95%
472.34	STRUCTURES AND IMPROVEMENTS - KINGSTON OFFICE	2046	40-S0.5	0%	16,737,576	4,069,504	12,668,072	704,663	18.0	4.21%
472.35	STRUCTURES AND IMPROVEMENTS - MAINWAY	2027	40-S0.5	0%	15,937,297	3,958,252	11,979,045	2,264,210	5.3	14.21%
473.01	SERVICES - METAL	0	40-S0.5	-32%	549,648,294	268,325,815	457,209,934	24,323,957	19.0	4.43%
473.02	SERVICES - PLASTIC	0	55-S3	-26%	4,458,883,265	1,384,833,504	4,233,359,410	121,567,634	35.7	2.73%
474.00	REGULATORS	0	25-SQ	0%	488,870,931	59,858,893	429,012,038	43,329,780	15.5	8.86%
475.00	MAINS - ENVISION	0	25-SQ	0%	181,264,676	59,887,548	121,377,128	10,469,399	12.2	5.78%
475.21	MAINS - COATED & WRAPPED	0	55-R3	-42%	3,320,418,328	1,051,359,036	3,663,634,991	112,249,761	34.9	3.38%
475.30	MAINS - PLASTIC	0	60-R4	-38%	3,480,106,028	928,431,883	3,874,114,436	94,562,548	42.0	2.72%
476.00	COMPANY NGV COMPRESSOR STATIONS	0	17-S2.5	0%	9,878,703	5,181,735	4,696,968	365,238	9.7	3.70%
477.00	MEASURING AND REGULATING EQUIPMENT	0	40-R2	-9%	950,956,098	367,887,432	668,654,715	27,440,188	23.3	2.89%
477.01	CUSTOMER M&R EQUIPMENT	0	35-R3	0%	143,726,981	52,094,469	91,632,512	4,800,551	19.4	3.34%
478.00	METERS	0	15-S2.5	0%	1,020,910,894	469,525,898	551,384,996	104,686,373	6.4	10.25%
TOTAL DISTRIBUTION PLANT					**14,994,747,798**	**4,751,912,857**	**14,380,634,082**	**559,603,098**		3.73%

TABLE 1. ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO PLANT IN SERVICE AT DECEMBER 31, 2021
Related to Total Expense

Account	Description	Truncation Date	Estimated Survivor Curve	Net Salvage Percent	Surviving Original Cost as of 12/31/2021	Book Reserve	Future Accruals	Annual Accrual Amount	Composite Remaining Life	Annual Accrual Rate
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
GENERAL PLANT										
482.00	STRUCTURES AND IMPROVEMENTS - OTHER	0	40-R1.5	0%	13,255,572	8,677,610	4,577,962	191,336	23.2	1.44%
482.01	STRUCTURES AND IMPROVEMENTS - VPC	2033	40-R1.5	0%	53,463,354	19,270,729	34,192,626	3,400,629	10.0	6.36%
482.04	STRUCTURES AND IMPROVEMENTS - THOROLD	2022	40-R1.5	0%	15,678,640	6,391,978	9,286,662	9,286,663	0.5	59.23%
482.05	STRUCTURES AND IMPROVEMENTS - MARKHAM	2046	40-R1.5	0%	36,671,818	6,852,980	29,818,839	1,544,848	19.3	4.21%
482.51	STRUCTURES AND IMPROVEMENTS - KEIL HEAD OFFICE	2049	40-R1.5	0%	69,558,675	11,589,939	57,968,736	3,906,954	16.4	5.62%
482.52	STRUCTURES AND IMPROVEMENTS - BLOOMFIELD TRAINING CENTER	2028	40-R1.5	0%	19,237,692	1,664,764	17,572,928	2,814,701	6.2	14.63%
483.00	OFFICE FURNITURE AND EQUIPMENT	0	15-SQ	0%	29,776,062	20,323,396	9,452,666	1,200,881	6.0	4.03%
484.00	TRANSPORTATION EQUIPMENT	0	12-L2.5	0%	134,722,078	89,525,829	45,196,249	6,268,747	5.7	4.65%
485.00	HEAVY WORK EQUIPMENT	0	17-L1.5	0%	44,128,921	12,811,266	31,317,655	3,658,037	8.6	8.29%
486.00	TOOLS AND WORK EQUIPMENT	0	15-SQ	0%	79,966,854	26,128,214	53,838,641	9,529,666	7.6	11.92%
487.70	RENTAL - REFUEL APPL	0	15-SQ	0%	864,755	92,164	772,591	86,895	9.3	10.05%
487.80	RENTAL - NGV STATIONS	0	20-SQ	0%	7,774,175	2,397,143	5,377,032	288,265	18.4	3.71%
488.00	COMMUNICATION STRUCTURES AND EQUIPMENT	0	10-SQ	0%	11,224,609	4,990,530	6,234,079	2,946,627	2.6	26.25%
490.00	COMPUTER EQUIPMENT	0	4-SQ	0%	30,306,679	20,774,567	9,532,112	4,041,429	1.7	13.34%
	COMPUTER EQUIPMENT - POST 2023	0	4-SQ	0%	0	0	0	0	0.0	25.00%
490.30	COMPUTER EQUIPMENT - WAMS	0	10-SQ	0%	4,680,899	2,418,465	2,262,435	502,763	4.5	10.74%
491.01	SOFTWARE ACQUIRED INTANGIBLES	0	4-SQ	0%	155,164,785	107,550,337	47,614,448	13,604,128	2.0	8.77%
	SOFTWARE ACQUIRED INTANGIBLES - POST 2023	0	4-SQ	0%	0	0	0	0	0.0	25.00%
491.02	SOFTWARE DEVELOPED INTANGIBLES	0	4-SQ	0%	38,776,288	25,519,357	13,256,930	3,892,471	2.2	10.04%
	SOFTWARE DEVELOPED INTANGIBLES - POST 2023	0	4-SQ	0%	0	0	0	0	0.0	25.00%
491.03	CIS ACQUIRED SOFTWARE	0	10-SQ	0%	87,626,214	20,250,171	67,376,042	7,217,716	8.4	8.24%
**	SOFTWARE INTANGIBLES - 10 YEAR	0	10-SQ	0%	0	0	0	0	0.0	10.00%
491.04	WAMS	0	10-SQ	0%	85,221,905	44,031,318	41,190,587	9,153,464	4.5	10.74%
TOTAL GENERAL PLANT					**918,099,975**	**431,260,756**	**486,839,219**	**83,536,220**		9.10%
TOTAL UTILITY PLANT STUDIED					**21,693,291,183**	**7,125,714,397**	**19,299,343,283**	**784,019,064**		**3.61%**
PLANT NOT STUDIED										
401.00	Franchises and Consents - Total Comp				1,175,081					
402.04	Other Intangibles - Lakeland Acquisition Adjustment				494,761					
458.00	Base Pressure and Line Pack Gas				76,135,052					
	Land (Including MacLeod Property)				177,293,391					
	Plant Held for Future Use				1,670,861					
	Inventory Adjustment				59,309,971					
***	Post Study Adjustments				5,005,525					
TOTAL PLANT NOT STUDIED					**321,084,642**					
TOTAL UTILITY PLANT IN SERVICE					**22,014,375,825**					

* Annual Accrual Rates for new major structures in Account 472.00 after 2023 are 4.02%.
** New depreciation rate for major longer term intangible asset additions post 2023
*** Adjustments between regulated and unregulated storage operations to align with updated exhibits in Enbridge Gas's 2021 Utility Earnings and Disposition of Deferral & Variance Account Balances proceeding (EB-2022-0110), as filed on September 2, 2022

2024-2028 Panhandle Regional Expansion Project

Line No.	Particulars ($ millions)	Revenue Requirement 2024	2025	2026	2027	2028	Average
		(a)	(b)	(c)	(d)	(e)	(f)
	Rate Base Investment						
1	Capital Expenditures	197.2	-	-	-	-	-
2	Cumulative Capital Expenditures	251.5	251.5	251.5	251.5	251.5	251.5
3	Average Investment	30.9	249.0	244.3	239.8	235.2	199.8
	Revenue Requirement Calculation:						
	Operating Expenses:						
4	Operating and Maintenance Expenses	0.0	0.1	0.1	0.1	0.1	0.1
5	Depreciation Expense (1)	0.4	4.6	4.6	4.6	4.6	3.7
6	Property Taxes	0.1	0.9	0.9	0.9	0.9	0.7
7	Total Operating Expenses	0.5	5.5	5.6	5.6	5.6	4.6
8	Required Return (2)	1.8	14.6	14.4	14.1	13.8	11.7
9	Total Operating Expense and Return	2.4	20.2	19.9	19.7	19.4	16.3
	Income Taxes:						
10	Income Taxes - Equity Return (3)	0.4	3.0	2.9	2.8	2.8	2.4
11	Income Taxes - Utility Timing Differences (4)	(16.5)	(4.4)	(3.8)	(3.4)	(2.9)	(6.2)
12	Total Income Taxes	(16.2)	(1.4)	(0.9)	(0.5)	(0.1)	(3.8)
13	Total Revenue Requirement	(13.8)	18.7	19.0	19.1	19.3	12.5
14	Incremental Project Revenue	0.6	4.0	6.3	7.1	7.9	5.2
15	Net Revenue Requirement	(14.4)	14.7	12.7	12.1	11.4	7.3

Notes:

(1) Depreciation expense at 2024 Proposed depreciation rates.

(2) The required return assumes a capital structure of 62% long-term debt at 4.17% and 38% common equity at the 2022 Board Formula return of 8.66%. The annual required return calculation is as follows:

Average Investment (row 3) * 62% * 4.17% plus Average Investment (row 3) * 38% * 8.66%

(3) Taxes related to the equity component of the return at a tax rate of 26.5%.

(4) 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.

ENBRIDGE GAS INC.

Accounting Entries for
Panhandle Regional Expansion Project (PREP) Variance Account
Account No. 179-329

This account records the difference between the actual net revenue requirement for the Panhandle Regional Expansion Project (PREP) and the actual revenues collected through the levelized PREP rate rider approved by the OEB. The actual net revenue requirement will include costs associated with the capital investment, including return on rate base, depreciation expense, and associated income taxes, as well as incremental operation and maintenance costs and property taxes, offset by transmission margin revenue associated with incremental demands served by the project. The actual revenues will be those collected through the PREP rate rider approved by the OEB for the Company.

Simple interest is to be calculated on the opening monthly balance of this account using the OEB-approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the OEB in a future rate application.

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit	-	Account No. 179-329 PREP Variance Account
Credit	-	Account No. 579 Miscellaneous Operating Revenue

To record as a debit/(credit) in the account the difference between the actual net revenue requirement for the PREP and the actual revenues collected through the PREP rate approved by the OEB.

Debit	-	Account No. 179-329 PREP Variance Account
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit/(credit) in the account, interest expense on the opening monthly balance.

2024 Dawn to Corunna Revenue Requirement

Line No.	Particulars ($ millions)	2024
		(a)
	Rate Base Investment	
1	Capital Expenditures	
2	Cumulative Capital Expenditures	
3	Average Investment	343.0
	Revenue Requirement Calculation:	
	Operating Expenses:	
4	Operating and Maintenance Expenses	0.0
5	Depreciation Expense (1)	8.9
6	Property Taxes	0.6
7	Total Operating Expenses	9.5
8	Required Return (2)	20.1
9	Total Operating Expense and Return	29.7
	Income Taxes:	
10	Income Taxes - Equity Return (3)	4.1
11	Income Taxes - Utility Timing Differences (4)	(11.3)
12	Total Income Taxes	(7.2)
13	Total Revenue Requirement	22.5
14	Incremental Project Revenue	-
15	Net Revenue Requirement	22.5

Notes:

(1) Depreciation expense at 2024 Proposed depreciation rates.

(2) The required return assumes a capital structure of 62% long-term debt at 4.17% and 38% common equity at the 2023 Board Formula return of 8.66%. The annual required return calculation is as follows:

Average Investment (row 3) * 62% * 4.17% plus Average Investment (row 3) * 38% * 8.66%

(3) Taxes related to the equity component of the return at a tax rate of 26.5%.

(4) 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.

Utility Operating Cost Summary - EGI
March Filing

Line No.	Particulars ($ millions)	Utility	2022 Estimate (a)	2023 Bridge Year (b)	2024 Test Year (c)	2022-2023 Variance (d)=(b-a)	2023-2024 Variance (e)=(c-b)
1	Gas Supply, Transportation & Storage Costs	EGI	2,440.1	3,047.3	3,228.0	607.1	180.7
2	Operating, Maintenance & Administrative Costs	EGI	963.8	1,021.7	1,046.0	57.9	24.3
3	Depreciation Expense	EGI	705.4	725.3	892.0	19.9	166.7
4	Other Financing	EGI	3.9	4.0	4.0	0.1	(0.0)
5	Income Tax	EGI	33.7	42.1	43.8	8.4	1.7
6	Property Tax	EGI	118.5	122.5	127.2	4.0	4.7
7	Total - Excluding Interest and Return (1)		4,265.5	4,962.9	5,341.0	697.4	378.1

Note:
(1) 2024 Test Year Forecast includes $5.0 million related to Dawn to Corunna.

Utility Operating Cost Summary - EGI
Capital Update

Line No.	Particulars ($ millions)	Utility	2022 Actual	2023 Bridge Year	2024 Test Year	2022-2023 Variance	2023-2024 Variance
			(a)	(b)	(c)	(d)=(b-a)	(e)=(c-b)
1	Gas Supply, Transportation & Storage Costs	EGI	3,630.3	3,047.3	3,228.0	(583.0)	180.7
2	Operating, Maintenance & Administrative Costs	EGI	1,002.3	1,021.7	1,054.0	19.4	32.3
3	Depreciation Expense	EGI	653.1	718.3	878.0	65.2	159.7
4	Other Financing	EGI	4.6	4.0	4.0	(0.6)	(0.0)
5	Income Tax	EGI	29.8	33.2	52.1	3.4	18.9
6	Property Tax	EGI	118.5	122.4	126.2	3.9	3.8
7	Total - Excluding Interest and Return (1)		5,438.5	4,946.8	5,342.4	(491.7)	395.4

Note:
(1) 2024 Test Year Forecast includes $2.3 million related to Dawn to Corunna.

Utility Operating Cost Summary
As Filed Versus Updated - Variance - EGI

Line No.	Particulars ($ millions)	Utility	2022	2023 Bridge Year	2024 Test Year
			(a)	(b)	(c)
1	Gas Supply, Transportation & Storage Costs	EGI	1,190.2	0.0	0.0
2	Operating, Maintenance & Administrative Costs	EGI	38.5	0.0	8.0
3	Depreciation Expense	EGI	(52.3)	(7.0)	(14.0)
4	Other Financing	EGI	0.7	0.0	0.0
5	Income Tax	EGI	(3.9)	(8.9)	8.3
6	Property Tax	EGI	(0.0)	(0.1)	(1.0)
7	Total - Excluding Interest and Return		1,173.1	(16.0)	1.3

2024 Utility Cost of Capital Summary - Test Year - EGI
Capital Update

Line No.	Particulars	Principal ($ millions)	Component (%)	Cost Rate (%)	Cost Component (%)	Cost ($ millions)
		(a)	(b)	(c)	(d) = (b x c)	(e) = (a x c)
1	Long and Medium Term Debt	10,028.1	61.85	4.17	2.58	418.0
2	Short Term Debt	23.5	0.15	3.00	0.00	0.7
3	Common Equity	6,160.7	38.00	8.66	3.29	533.5
4	Total	16,212.3	100.00		5.87	952.2

2024 Utility (Deficiency)/Sufficiency Calculation and Required Rate of Return - Test Year - EGI
Capital Update

Line No.	Particulars	Principal ($ millions)	Component (%)	Cost Rate (%)	Cost Component (%)
		(a)	(b)	(c)	(d) = (b x c)
	Debt				
1	Long and Medium Term Debt (1)	10,028.1	61.85	4.17	2.578
2	Short Term Debt	23.5	0.15	3.00	0.004
3	Total Debt	10,051.6	62.00		2.582
4	Common Equity	6,160.7	38.00	8.66	3.291
5	Total	16,212.3	100.00		5.873
6	Rate Base	16,212.3			
7	Utility Income	738.3			
8	Indicated Rate of Return	4.554%			
9	(Deficiency)/Sufficiency in Rate of Return	(1.320%)			
10	Net (Deficiency)/Sufficiency	(213.9)			
11	Gross (Deficiency)/Sufficiency (1)	(291.0)			
12	Revenue at Existing Rates	6,016.3			
13	Revenue Requirement	6,307.4			
14	Gross Revenue (Deficiency)/Sufficiency (1)	(291.0)			
	Common Equity				
15	Allowed Rate of Return	8.660%			
16	Earnings on Common Equity	5.188%			
17	(Deficiency)/Sufficiency In Common Equity Return	(3.472%)			

Note:
(1) Includes ($22.5) million related to Dawn to Corunna.

2024 Test Year - Calculation of Total Revenue Deficiency
Capital Update

Line No.	Particulars ($ millions)	Reference	Delivery	Gas Supply	Total
	Cost of Capital				
1	Rate Base	Exhibit 2, Tab 5, Schedule 4, Table 10	16,212.3		16,212.3
2	Required Rate of Return	Exhibit 2, Tab 5, Schedule 4, Attachment 5	5.87%		5.87%
3	Required Return		952.2		952.2
	Cost of Service				
4	Gas Costs	Exhibit 2, Tab 5, Schedule 4, Attachment 4	17.6	3,210.4	3,228.0
5	Operations and Maintenance	Exhibit 2, Tab 5, Schedule 4, Attachment 4	1,054.0	-	1,054.0
6	Depreciation and Amortization	Exhibit 2, Tab 5, Schedule 4, Attachment 4	878.0	-	878.0
7	Fixed Financing Costs	Exhibit 2, Tab 5, Schedule 4, Attachment 4	4.0	-	4.0
8	Municipal and Other Taxes	Exhibit 2, Tab 5, Schedule 4, Attachment 4	126.2	-	126.2
9	Total		2,079.8	3,210.4	5,290.3
	Miscellaneous Operating and Non-Operating Revenue				
10	Other Operating Revenue	Exhibit 3, Tab 1, Schedule 1	(64.3)	-	(64.3)
11	Other Income	Exhibit 3, Tab 1, Schedule 1	-	-	-
12	Total		(64.3)	-	(64.3)
	Income Taxes on Earnings				
13	Excluding Tax Shield		169.0	(6.1)	162.9
14	Tax Shield Provided by Interest Expense		(110.8)	-	(110.8)
15	Total	Exhibit 2, Tab 5, Schedule 4, Attachment 4	58.2	(6.1)	52.1
	Taxes on (Deficiency)/Sufficiency				
16	Gross (Deficiency)/Sufficiency		(267.9)	(23.2)	(291.0)
17	Net (Deficiency)/Sufficiency		(196.9)	(17.0)	(213.9)
18	Total		71.0	6.1	77.1
19	Revenue Requirement		3,096.9	3,210.5	6,307.4
20	Revenue At Existing Rates				
21	Gas Sales	Exhibit 3, Tab 2, Schedule 1, Attachment 3	2,666.9	3,184.7	5,851.6
22	Transmission, Compression & Storage	Exhibit 3, Tab 4, Schedule 1, Attachment 1	162.2	2.5	164.7
23	Total Revenue At Existing Rates		2,829.1	3,187.2	6,016.3
24	Gross Revenue (Deficiency)		(267.8)	(23.2)	(291.0)
25	Adjustments to Gross Revenue (Deficiency)				
26	Gross Revenue (Deficiency) Attributed to Dawn to Corur	Exhibit 2, Tab 5, Schedule 4, Attachment 3	22.5	-	22.5
27	Gross Revenue (Deficiency) Excluding Dawn to Corunna		(245.3)	(23.2)	(268.5)
28	Adjustment for Levelized PREP Proposal	Exhibit 2, Tab 5, Schedule 4, Attachment 2	(7.3)	-	(7.3)
29	Gross Revenue (Deficiency) Excluding Dawn to Corunna, Including Levelized PREP Proposal		(252.6)	(23.2)	(275.8)

2024 Net Utility Income - EGI
Capital Update

Line No.	Particulars ($ millions)	2024 Test Year
	Operating Income	
1	Gas Sales and Distribution	5,851.6
2	Transportation	164.7
3	Storage	0.0
4	Other Operating Revenue	64.3
5	Interest and Property Rental	-
6	Other Income	-
7	Total Operating Revenue	6,080.6
	Operating Cost	
8	Gas Costs	3,228.0
9	Operation and Maintenance	1,054.0
10	Depreciation and Amortization Expense	878.0
11	Fixed Financing Costs	4.0
12	Debt Redemption Premium Amortization	0.0
13	Municipal and Other Taxes	126.2
14	Cost of Service	5,290.3
15	Utility Income Before Income Taxes	790.4
16	Income Tax Expense	(52.1)
17	Utility Income (1)	738.3

Note:
(1) Includes ($2.3) million related to Dawn to Corunna.

2024 Test Year - Drivers of Delivery Revenue Deficiency
March Filing

Line No.	Particulars ($ millions)	Gross (Deficiency)/ Sufficiency	Relative Contribution
1	Net sustainable synergies and productivity	67.2	(25%)
2	Changes in accounting policy and methodologies	25.6	(9%)
3	Impact related to ICM and Capital Pass Through	(42.0)	16%
	Deferred Rebasing Impact	50.8	(19%)
4	Cost pressures	(135.0)	50%
5	Higher depreciation resulting from new depreciation study	(160.4)	59%
6	Increase equity thickness from 36% to 38% in 2024	(26.3)	10%
	Cost of Service Impacts	(321.7)	119%
7	Total Gross 2024 Test Year Deficiency	(270.9)	100%

2024 Test Year - Drivers of Delivery Revenue Deficiency
Capital Update

Line No.	Particulars ($ millions)	Gross (Deficiency)/ Sufficiency	Relative Contribution
1	Net sustainable synergies and productivity	74.2	(28%)
2	Changes in accounting policy and methodologies	25.6	(10%)
3	Impact related to ICM and Capital Pass Through	(42.0)	16%
	Deferred Rebasing Impact	57.8	(22%)
4	Cost pressures	(143.0)	53%
5	Higher depreciation resulting from new depreciation study	(156.5)	58%
6	Increase equity thickness from 36% to 38% in 2024	(26.1)	10%
	Cost of Service Impacts	(325.6)	122%
7	Total Gross 2024 Test Year Deficiency (1)	(267.8)	100%

Note:
(1) Includes ($22.5) million related to Dawn to Corunna.

UTILITY SYSTEM PLAN

COLIN HEALEY, DIRECTOR FINANCIAL PLANNING & ANALYSIS

BOB WELLINGTON, MANAGER ASSET MANAGEMENT GOVERNANCE AND RISK

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1. Introduction

1.1 Purpose

1. This is Enbridge Gas Inc.'s (Enbridge Gas) Utility System Plan (USP) covering the 2024 to 2028 period which describes how the Company plans, strategizes, prioritizes and optimizes expenditures to produce investment plans that meet the needs of customers and the expectations set out in the Ontario Energy Board's (OEB) Renewed Regulatory Framework (RRF). Enbridge Gas has requested a multi-year incentive rate-setting mechanism (IRM) be used to set regulated distribution, transportation, and storage rates for the period January 1, 2025, to December 31, 2028 (IR term). Enbridge Gas is proposing rates during the IR term be set based on a price cap incentive rate-setting (Price Cap IR) mechanism and associated parameters. The first year of the IR term will apply the Price Cap IRM parameters to rates set through 2024 Rebasing.

2. In its MAADs Decision, the OEB indicated that it expected Enbridge Gas to file a consolidated USP for any Incremental Capital Module (ICM) request for 2021 rates and beyond.[1] Pursuant to the OEB's decision, Enbridge Gas filed a consolidated USP for the 2021 Rate Application with a consolidated Asset Management Plan (AMP) and a Customer Engagement Report to inform Enbridge Gas's Asset Plan[2].

3. The USP describes how Enbridge Gas meets the needs of customers across its entire service area through asset management that supports the delivery of safe and reliable service. 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. Enbridge Gas's 2023 to 2032 AMP (the AMP) is provided at Exhibit 2, Tab 6, Schedule 2.

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[1] EB-2017-0306/EB-2017-0307 Decision and Order, August 30, 2018, pp.33 to 34.
[2] EB-2020-0181, Exhibit C, Tab 1, Schedule 1 and Exhibit C, Tab 2, Schedule 1, and Exhibit C, Tab 3, Schedule 1.

4. Enbridge Gas is proposing to file an AMP every two years, and an update or addendum to the AMP in the intervening years. In a year where there is an ICM request, the AMP (or AMP update/addendum) will be filed as supporting evidence to Enbridge Gas's request for approval of ICM funding in the annual rate case. In a year where there is no ICM request, the AMP (or AMP update/addendum) will be filed with a cover letter indicating that it is being filed as directed by the IRP Framework. Enbridge Gas will not be requesting any approvals of the AMP (or AMP update/addendum) in relation to each of the filings.

5. Enbridge Gas conducted an extensive customer engagement process over the course of 2021 and early 2022 to support this rebasing application. It leveraged previous customer engagement, existing research, the experience of Innovative Research Group, and considered the broader business planning process. Various meetings took place to ensure customer engagement content reflected the current state of planning as well as to ensure that planners were familiar with customer needs and preferences as they were identified. As plans evolved, so too did the customer engagement, with each progress phase containing more detailed background information and more specific trade-offs. Customer engagement details are provided at Exhibit 1, Tab 6, Schedule 1.

1.2 OEB Filing Requirements

6. On February 16, 2017, the OEB issued amended filing requirements for natural gas rate applications (the Filing Requirements)[3]. Section 2.2.6 of the Filing Requirements provides the filing requirements for a USP. Enbridge Gas is filing this USP in support of its 2024 Cost of Service Application. In addition to the Filing

[3] Filing Requirements for Natural Gas Rate Applications, February 16, 2017, p. 21.

Requirements, there are several other OEB policies which informed the creation of Enbridge Gas's USP. These policies include:

a) The Handbook for Utility Rate Applications (Handbook)[4];
b) 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;
c) The OEB's guidelines for natural gas utilities' transportation and distribution system projects (EBO 134[5] and EBO 188[6]); and
d) Chapter 5 of the Filing Requirements for Electricity Distributor Applications[7], which provides further guidance from the OEB on components of a Distribution System Plan, which is informative to certain components of the USP.

1.3 Enbridge Gas's System Overview

7. Enbridge Gas has over $14 billion in regulated assets and serves over 3.8 million residential, commercial, and industrial customers in Ontario delivering heating to more than 75% of Ontario's homes. Enbridge Gas's service area is divided into the following seven operating regions:

a) Northern Region covers the Northwest and Northeast districts stretching from Kenora to Orillia;
b) Eastern Region covers Ottawa and Eastern district stretching from Belleville to Ottawa;
c) Southwest Region covers the Windsor/Chatham and the Sarnia/London districts;

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[4] Handbook for Utility Rate Applications, October 13, 2016.
[5] *Report on the Expansion of Natural Gas System in Ontario* (E.B.O. 134), June 1, 1987.
[6] *Final Report of the Board and the Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario* (E.B.O. 188) January 30, 1998.
[7] Filing Requirements For Electricity Distribution Rate Applications – 2018 Edition for 2019 Rate Applications – Chapter 5 Consolidated Distribution System Plan, July 12, 2018.

d) Southeast Region covers the Niagara, Waterloo/Brantford, and Hamilton districts;
e) Greater Toronto Area (GTA) West and Halton Region covers the western GTA and Halton districts;
f) GTA East Region covers the eastern GTA; and
g) Toronto Region covers the City of Toronto.

8. Enbridge Gas has storage and transmission assets that serve to receive, store, and transport natural gas for markets in Ontario, Québec, the Maritimes, and major United States (U.S.) natural gas-consuming areas. 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 Western Canadian Sedimentary Basin and the Utica and Marcellus-producing regions in the U.S. It is similarly connected to the major demand markets with more than half a dozen major pipelines connected at Dawn. Enbridge Gas's transmission assets link the extensive network of underground storage pools at the Dawn Hub to major Canadian and U.S markets and forms an important link in transporting gas from the Dawn Hub to the GTA through its West, Central, and East transmission operations areas.

9. Enbridge Gas owns and operates approximately 153,000 km of main and service pipelines for the transportation and distribution of gas. In addition, Enbridge Gas owns and operates approximately 311 petajoules (PJ) of underground gas storage facilities (199 PJ regulated and 112 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 1,895 fleet vehicles, plus heavy equipment and tools. Enbridge Gas has 84 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.

10. A map of Enbridge Gas's assets and operations, as well as where the utility operates in the province, and the communities it services is provided at Exhibit 1, Tab 4, Schedule 1, Attachment 1. This map identifies the location of gas transportation assets, compressor stations and interconnects, underground storage facilities, liquefied natural gas facilities, and any other assets.

11. Enbridge Gas's transmission system and distribution networks operate with a high level of reliability. Enbridge Gas delivers customers consistent and dependable service with minimal disruptions or force majeures. Enbridge Gas maintains this operating performance as a direct outcome of its asset class strategies, objectives, and asset investment planning and prioritization process, as described in this USP and AMP.

1.4 Enbridge Gas's Strategic Priorities

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

13. Enbridge Gas's strategic priorities and alignment with the RRF are provided 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 it operates can be found on the Company's safety page at www.enbridgegas.com/safety.
2. Optimize the Base Business	Customer Focus, Operational Effectiveness and Financial Performance	The integration of Enbridge Gas drove opportunities for 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 Ontario's energy sector.
3. Execute Capital Program	Customer Focus, Operational Effectiveness and 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 safe and reliable infrastructure is maintained to satisfy customers' energy needs. Forecasting a long-term asset investment plan and ensuring money is spent on the right

Strategic Priority	RRF Outcome	Description
		things at the right time helps to ensure the distribution system is maintained in the most reliable and cost-effective way. Therefore, it is 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 organizational 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 reliable and cost-effective source of energy. Enbridge Gas has several community expansion projects completed or underway, made possible through government funding under the Natural Gas Expansion Program. The program expands access to safe, reliable, and affordable natural gas to rural, northern and Indigenous communities. A strong Asset Management program allows for value-based decision-making, where optimizing/prioritizing is based on risk and opportunity. Enbridge Gas will continue to

Strategic Priority	RRF Outcome	Description
		bolster the Asset Management program through the integration of Integrated Resource Planning (IRP).
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 orderly transition to a lower carbon economy by supporting a diversified pathway to net-zero emissions in Ontario. Examples of this include programs such as Renewable Natural Gas, Compressed Natural Gas/Natural Gas Vehicle, IRP, Hydrogen Blending and other low carbon technologies.

2. Economic and Planning Assumptions

2.1 Energy Transition Plan

14. Enbridge Gas has developed an Energy Transition Plan (ETP) to demonstrate how energy transition has been considered and included within the Company's business and rebasing planning and proposals. The ETP is provided at Exhibit 1, Tab 10, Schedule 6.

15. The objectives of Enbridge Gas's ETP are to 1) support an orderly energy transition in Ontario by identifying and proposing safe bet actions, defined as actions that will be needed in the future regardless of the pathway to net-zero that is taken, 2) provide cost-effective, secure, reliable and resilient energy for customers during the transition to a low-carbon economy and once net-zero is achieved, and 3) ensure consistency with provincial and federal energy and climate change targets and policies.

16. As part of Enbridge Gas's ETP, the Company has considered energy transition in the Company's forecasting processes, which is an important input in the Company's planning activities, including the Asset Management Plan and process, gas supply planning and rate setting. Adjustments to the forecast to reflect energy transition are based on an understanding of climate policies, results of energy transition scenario analysis, and stakeholder engagement. Energy transition adjustments in the forecasting process are provided at Exhibit 1, Tab 10, Schedule 4.

17. Enbridge Gas intends to continue to evolve the ETP and how energy transition is integrated into the Company's planning activities over time. Details on ongoing evolution of the ETP are provided at Exhibit 1, Tab 10, Schedule 6, Section 4.

2.2 Current Budget Cycle Assumptions

18. Enbridge Gas completes an annual budget and multi-year, long-range planning (LRP) process, which reflects a forecast of annual volumes, revenues, operating costs and capital investments. This process is underpinned by key economic and financial assumptions provided at Exhibit 3, Tab 2, Schedule 4. These assumptions are obtained from both internal and external sources and are reviewed and approved by management.

19. The key economic and financial assumptions are derived and finalized at a particular point in time as part of the budget and LRP process. However, assumptions and/or actual experience may differ after the date of finalization. Specifically, Enbridge Gas has not adjusted the 2022 to 2024 forecasts to reflect the increases in inflation that have occurred since Q1 2022.

20. The key assumptions and sources of information are detailed below:
    a) Distribution Revenue inflation: The revenue escalator for 2023 is determined by a price cap index (PCI), where PCI growth is driven by an inflation factor using Gross Domestic Product Implicit Price Indicator for Final Domestic Demand (GDP IPI FDD), less a productivity factor of zero and a stretch factor of 0.30% (X factor). This is determined in accordance with the 2019 to 2023 IRM framework as approved in the MAADs Decision[8]. Revenues for 2024 are based on cost of service as provided at Exhibit 3, Tab 1, Schedule 1.
    b) Merit escalation: This assumption is determined by the corporate compensation function and is applied to non-unionized salary and wages costs. Unionized wages are escalated in accordance with the respective collective agreements in place.
    c) Non-wage inflation: Inflation assumptions are applied to current cost estimates, unless there are known and identifiable adjustments (increases/decreases) to cost estimates that are required to reflect current market conditions, for example, where different inflation assumptions should be applied (e.g. fuel, postage and renegotiated contracts). Normal inflationary impacts within Enbridge Gas's AMP are expected to be covered within the investment contingency.

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

d) Foreign exchange and interest rates: These financial indicators are issued from the corporate treasury and risk function and are based on the average of forecasts from external sources and historical differentials.
e) Annual volume forecast: The annual volume forecasts for the 2023 Bridge Year are prepared separately for the EGD and Union rate zones, using OEB-approved methodologies and criteria. The annual volume forecast for 2024 is prepared using the new methodologies that are proposed for Enbridge Gas and provided at Exhibit 3, Tab 2, Schedules 7 and 8. The underlying assumptions used in the forecast are provided at Exhibit 3, Tab 2, Schedule 4. Adjustments for energy transition are provided at Exhibit 1, Tab 10, Schedule 4.
f) Customer Additions: Enbridge Gas customer additions forecast for 2024 is provided at Exhibit 3, Tab 2, Schedule 6 and Exhibit 3, Tab 2, Schedule 8. Adjustments for energy transition are provided at Exhibit 1, Tab 10, Schedule 4.

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

2.3 Expectations of Natural Gas Prices

22. As the effects of COVID-19 and other global events continue to impact natural gas markets worldwide, price volatility has become a primary concern. The futures market is continuing to project increases in Henry Hub natural gas prices for the 2022/2023 winter from historically low levels for the past several years.

23. Below average natural gas inventories combined with more severe weather events have triggered price increases in areas of the U.S. that are routinely constrained for

peak capacity in the winter. Another significant pressure on pricing is the increased demand for natural gas exports, predominantly via liquified natural gas to Asia and Europe. In response to the Ukraine/Russia conflict, Western Europe is seeking to wean itself off Russian natural gas, driving demand for liquified natural gas to unprecedented levels[9]. With high demand for U.S. natural gas exports, increases in global natural gas prices have coincided with price increases at Henry Hub.

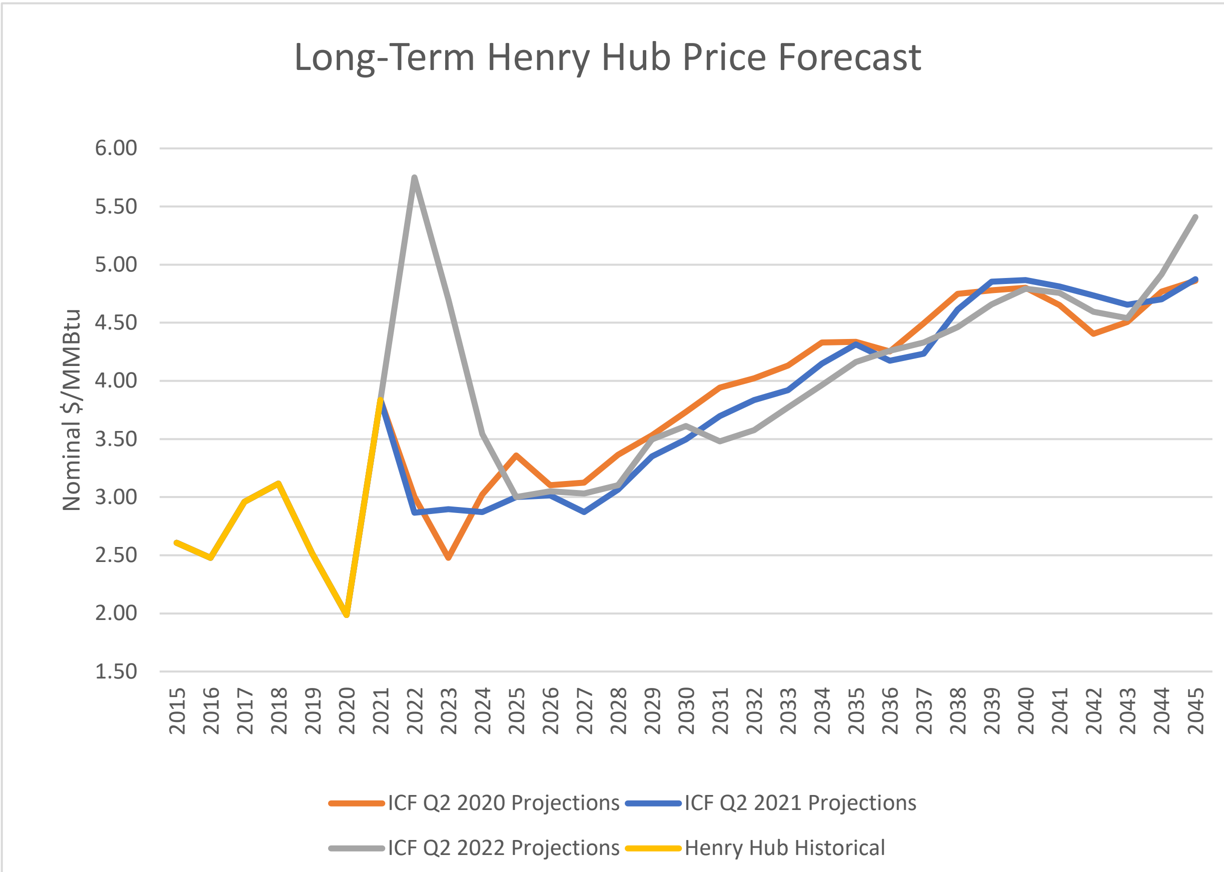
Natural Gas Price Signals

24. Natural gas futures prices set by the New York Mercantile Exchange (NYMEX) for deliveries at Henry Hub are generally seen to be the primary price for the North American natural gas market. Prices for gas at other locations are generally set using a locational basis differential to NYMEX. ICF's long-term price forecast reflects the transition of the Henry Hub to a major demand center with prices between $2.65 and $5.57 per MMBtu in real terms[10].

[9] Natural Gas Intelligence.(June 7, 2022). EIA Confirms Russia's War Forces Seismic Shift in U.S. LNG Demand. https://www.naturalgasintel.com/eia-confirms-russias-war-forces-seismic-shift-in-u-s-lng-demand/

[10] ICF Forecast: Natural Gas – Strategic, Q2 2022 Outlook. Used with permission.

Figure 1: Long-Term Natural Gas Prices[11]



Carbon Pricing Forecast

25. In 2019, the federal government enacted a national carbon price through the establishment of the Greenhouse Gas Pollution Pricing Act (GGPPA). An overview of the GGPPA is provided at Exhibit 1, Tab 10, Schedule 3, Section 2.

26. Under the GGPPA, Enbridge Gas is required to remit payment to the Government of Canada for the Federal Carbon Charge (FCC) on all volumes of natural gas the Company delivers in Ontario. Through OEB-approval, the FCC is passed through to

[11] ICF Forecast: Natural Gas – Strategic, Q2 2022 Outlook. Used with permission.

customers on their Enbridge Gas bill.[12] The charge rate for the FCC is determined by the government based on the price of carbon in \$/tonne of carbon dioxide equivalent (\$/tCO_2e) and is provided in Table 2. The rate increases as of April 1 each year.

Table 2

Federal Carbon Charge Rates[13]

Year	Price of Carbon (\$/tCO_2e)	FCC Rate (¢/m^3)
2022	50	9.79
2023	65	12.39
2024	80	15.25
2025	95	18.11
2026	110	20.97
2027	125	23.83
2028	140	26.69
2029	155	29.54
2030	170	32.40

27. Enbridge Gas is also required to remit payment to the Government of Canada for the FCC on volumes of natural gas used at company-owned facilities. The Company's transmission compressor stations are also covered under the provincial Greenhouse Gas Emissions Performance Standards (EPS) regulation, which is provided at Exhibit 1, Tab 10, Schedule 3, Section 2. With OEB approval, FCC costs for company-owned facilities and costs related to the EPS are passed through to customers through the Facility Carbon Charge which is included in distribution rates on their Enbridge Gas bill. The Facility Carbon Charge is determined annually through the Federal Carbon Pricing Program Application.[14] Due to the escalating

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[12] EB-2021-0209, OEB Decision and Order, February 10, 2022.
[13] Government of Canada. (2021, December 3).Fuel Charge Rates for Listed Provinces and Territories for 2023 to 2030. Department of Finance Canada. https://www.canada.ca/en/department-finance/news/2021/12/fuel-charge-rates-for-listed-provinces-and-territories-for-2023-to-2030.html
[14] EB-2022-0194, 2023 Federal Carbon Pricing Program Application.

price of carbon, it is anticipated that the Facility Carbon Charge will increase each year.

3. Company Budget and Long-Range Planning (LRP) Process

3.1 Overview

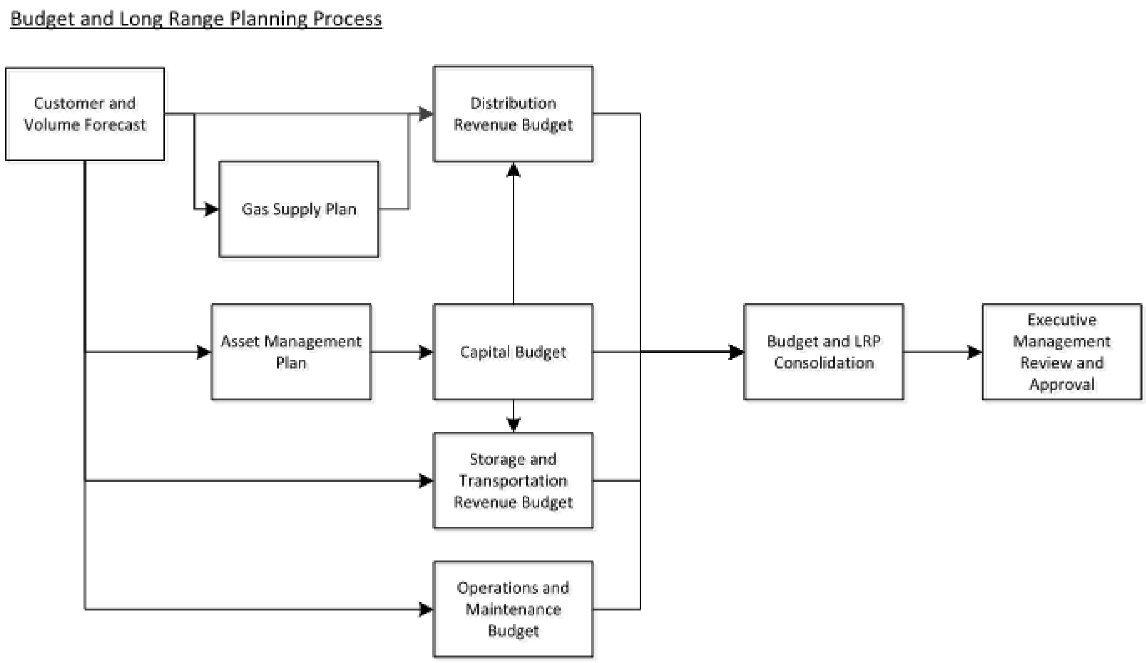
28. Each year, Enbridge Gas completes a budget and multi-year LRP process. This process produces Enbridge Gas's forecast of annual volumes, revenues, operating costs, and capital investments. The budget and LRP processes allow the Company to execute and monitor its strategic priorities, including monitoring its financial viability in support of maintaining safe and reliable operations.

29. The annual volume forecast is the starting point for the budget and LRP process. The volume forecast provides inputs into the four main components of Enbridge Gas's financial budget and LRP process listed below, as well as the Gas Supply Plan process detailed within the distribution revenue budget process.

30. Each component of the budget and LRP is individually described in the following sections:
    a) Distribution Revenue;
    b) Storage and Transportation Revenue;
    c) Operations and Maintenance Costs; and
    d) Capital Investment.

31. 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, GDP forecasts, and provincial housing starts, where applicable.

Figure 2: Budget and Long-Range Planning Process Map



3.2 Revenue and Volume Forecast

32. The starting point for the planning process is the customer and volume forecast. This forecast underpins the development of both the revenue and cost components of the budget and LRP and, it is used as an input into the IRP and Asset Investment Planning and Management (AIPM) process.

Distribution Revenue Budget

33. The distribution revenue budget is comprised of two distinct segments of customers: general service and contract. The forecast for the general service segment applies forecast rates for each year of the budget and LRP to the volume and customer forecast in order to derive the general service revenue forecast for the utility. The contract segment uses customer specific information to derive

volumes and daily contracted demand. Those parameters are multiplied by rates to derive the distribution contract market revenue forecast for the utility.

Distribution Revenue – General Service Customers

34. The general service customer segment consists of residential and non-residential (apartment, commercial and industrial) customers. This segment is temperature-sensitive and is also influenced by economic conditions, housing starts, natural gas price, efficiency factors and energy conservation measures. This segment is also expected to be impacted by energy transition and climate change policies such as building codes and Community Energy Plans. The forecast is developed using the OEB-approved methodology and criteria for the 2023 Bridge Year and proposed methodologies and criteria for the 2024 Test Year. These customers consume natural gas in a seasonal load profile, consuming more natural gas from November through March than the spring and summer months.

35. The base volume forecast for the general service segment is calculated on the projected number of customers and forecast average use per customer. The customer forecast is based on the current customer base plus forecasted customer additions less customer shrinkage/locked customers. This base volume forecast is then adjusted for forecast Demand Side Management activity and other factors that cannot be captured through the forecasting methodology. Gas consumption is forecasted for those current and forecasted customers and applied to the assumed rates to create a revenue forecast.

Distribution Revenue – Contract Class Customers

36. The contract customer segment typically has higher consumption levels and is less temperature sensitive than the general service customer segment. Volume and demand for these customers are based primarily on process load which is linked

more closely to factors such as economic conditions industry and sector growth, and customer expansion/contraction plans. This segment is also expected to be impacted by energy transition and climate change policies such as energy conservation, carbon pricing, and fuel switching policies.

37. The volume and daily contract demand forecast for this segment is developed for both current and new customers. The forecast for existing customers is based on the current contract parameters, which includes adjustments provided by customers for known changes to their operational plans and expectations, including the impact of energy transition on current and future energy requirements. The forecast for new customers is based on anticipated volumes and daily contract demand associated with discrete capital projects included in the AMP and capital budget for projects that are anticipated to go into service in the forecast period, as well as for customer requests for connection that are highly likely to materialize are a modification to current contract parameters. 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 greenhouse market), and, by general trends, reflective of industry and general economic conditions. Where available, direct customer input is factored in Enbridge Gas's forecast.

Distribution Revenue – Incremental Capital Module

38. Through the Capital Budget process outlined below, while the Company is operating under a price cap, eligible ICM projects benefiting in-franchise customers are identified. For those projects that meet the ICM eligibility criteria, the annual revenue requirements are calculated and subsequently reflected in the total distribution revenue budget.

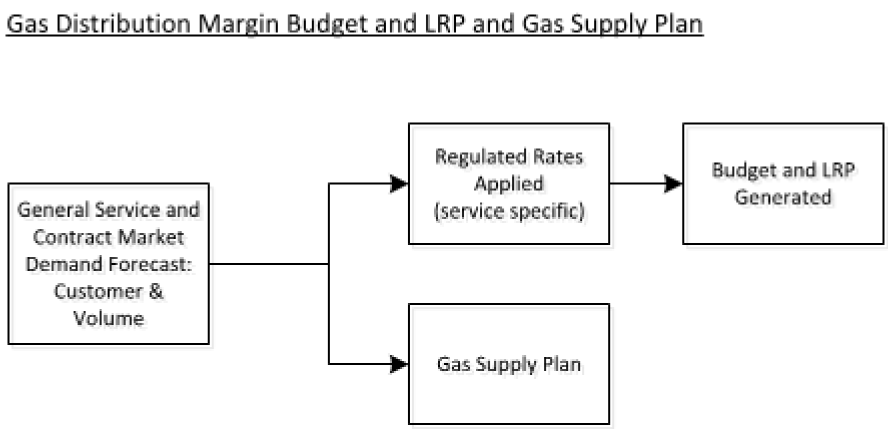
Distribution Volume Forecast as an Input to the Gas Supply Plan

39. The volume forecast for the Distribution segment is provided to the Gas Supply department for inclusion in the development of the Gas Supply Plan. The Gas Supply Plan is provided at Exhibit 4, Tab 2, Schedule 1.

40. The objective of the Gas Supply Plan is to identify an 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. The Gas Supply Plan is developed 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.

41. The Gas Supply Plan is proposed to include up to a 5% blend of green energy by 2028 as part of Enbridge Gas's short-term action plan for energy transition. Additional details of this proposal are provided at Exhibit 4, Tab 2, Schedule 7.

Figure 3: Distribution Revenue Budget and Gas Supply Plan



Storage and Transportation Revenue Budget

42. The storage and transportation (S&T) budget and LRP revenues are derived from the services provided by Enbridge Gas's storage and transportation assets.

Storage Revenue

43. 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. Starting in 2024, with the harmonization to a single rate zone, this excess storage space is now proposed to be used to serve all Enbridge Gas in-franchise customers. Please see Exhibit 4, Tab 2, Schedule 1 for further details.

Transportation Revenue

44. The transportation revenue budget is based on the Company's sale of its transmission pipeline capacity. Enbridge Gas sells both short-term and long-term transportation capacity.

45. The transportation revenue forecast is based on current contracted demand as well as forecasted future demands. Ongoing customer discussions inform Enbridge Gas of changes to future demand 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.

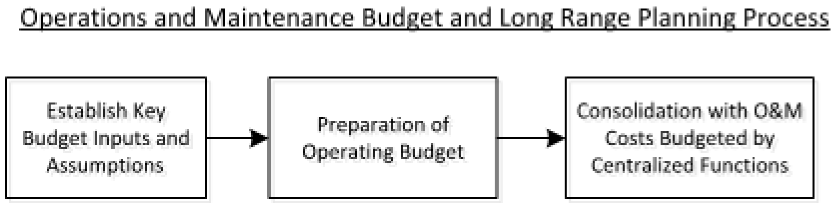
46. If available capacity is insufficient to meet the existing and forecasted future demand for transportation services, additional capacity may be created through the construction of new facilities or the consideration of integrated resource planning alternatives to meet the incremental demand. Capacity demands for both in-franchise customers and ex-franchise customers are factored into the AMP for asset classes providing these services.

47. Long-term transportation services are priced based on regulated rate schedules. 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 demand.

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

48. The major steps in the O&M Budget process are illustrated in Figure 4 and described below:
    a) Establish Key Budget Inputs and Assumptions
    b) Preparation of Operating Budget
    c) Consolidation with O&M Costs Budgeted by Centralized Functions

Figure 4: O&M Budget Process



Establish Key Budget Inputs and Assumptions

49. Assumptions are obtained by Finance from corporate and external sources for key input variables, including GDP growth, inflation, foreign exchange rates and expectations for compensation increases.

Preparation of Operating Budget

50. 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 first adjusted for compensation changes and inflation. It is then adjusted for any new program additions or deletions, any material changes to existing programs, or any other known cost changes. Ongoing O&M costs associated with capital projects that have been placed into service are also incorporated. Changes in staffing requirements are similarly considered, including the need to engage consultants or employ contract employees to complete workload requirements 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. Finally, O&M amounts are applied overhead capitalization rates to recognize indirect capital costs.

Consolidation with O&M Costs Budgeted by Centralized Functions

51. There are a number of centralized functions such as Finance, Human Resources, Technology & Information Services, Supply Chain Management, Real Estate & Workplace Services and Enterprise Safety & Operational Reliability which 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 (e.g. TIS application support). Costs associated with these centralized functions are allocated through a central function cost allocation methodology provided at Exhibit 4, Tab 4, Schedule 3 to ensure that Enbridge Gas is paying an appropriate amount for the services it receives from these centralized functions. Allocated amounts for centralized functions are similarly applied with overhead capitalization rates to recognize indirect capital costs.

3.4 Capital Budget Process

52. There are two primary objectives of the capital budget process:
    a) Ensure the proper governance structure and level of management oversight to enable Enbridge Gas to invest capital in the most efficient and effective way to meet the Company's obligations, ensure safety and reliability, and maximize the value of the investments; and
    b) 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 Enbridge Gas serves.

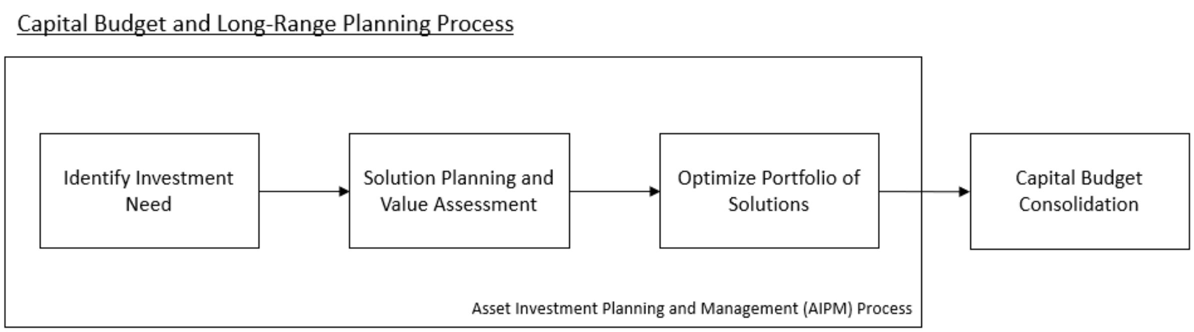
53. The capital budgeting process is underpinned by the AMP and the AIPM process provided at Exhibit 2, Tab 6, Schedule 2, Section 4.3. The AMP also takes into consideration assumptions on the impacts of energy transition when developing

the long-range reinforcement plan; and presents the facility solution against which Integrated Resource Planning Alternatives (IRPAs) can be compared.

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

a) Identify Investment Need
b) Solution Planning and Value Assessment
c) Optimization Portfolio of Solutions

Figure 5: Capital Budget and LRP Process



Identify Investment Need

55. Enbridge Gas identifies investment needs in accordance with its AIPM process. The main drivers for capital needs are:

a) System integrity expenditures required to maintain or enhance the safety and reliability of Enbridge Gas's plant, as well as to ensure compliance with codes and regulations governing the industry;
b) System relocation expenditures required as a result of requests from municipalities and others under the terms of franchise or other occupancy agreements;
c) Capital expenditures to replace plant, vehicles and equipment, computer hardware and software as a result of age, condition, or obsolescence;

d) Capital expenditure requirements to meet expected growth as identified through the demand/revenue planning process and the gas supply planning process;
e) Capital expenditures to support the ETP; and
f) New programs that result in the need for capital expenditures

56. Specific capital projects are identified to address the needs articulated above. Enbridge Gas has also implemented an IRP Assessment process on eligible projects to determine the most cost-effective solution to meet specific system needs, which includes consideration of both facility and IRP alternatives. The summary of EGI's IRP Assessment is provided at Exhibit 2, Tab 6, Schedule 2, Section 6.3.

Solution Planning and Value Assessment

57. Enbridge Gas completes solution planning and value assessment in accordance with its AIPM process.

58. Further information outlining the Leave-to-Construct (LTC) criteria for projects/programs is provided in Sections 7.1 and 7.2.

59. Economic analysis of system expansion projects is completed using a Discounted Cash Flow (DCF) analysis. E.B.O 188[15] and E.B.O 134[16] describe the parameters and methodology for the DCF.
    a) E.B.O 188 describes the economic test that should be used to evaluate a proposed expansion of a gas distribution system.

[15] *Final Report of the Board and the Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario* (E.B.O. 188), January 30, 1998,
[16] *Report on the Expansion of Natural Gas System in Ontario* (E.B.O. 134), June 1, 1987.

b) E.B.O 134 describes the economic test that should be used to evaluate a proposed expansion of a gas transmission system.

Optimization Portfolio of Solutions

60. Enbridge Gas optimizes its portfolio of solutions in accordance with its AIPM process. Capitalized overheads are then allocated to capital projects based on the total spend of the Enbridge Gas portfolio.

3.5 Budget Approval

61. Once all of the components of the budget are prepared, the overall budget and LRP is consolidated and then reviewed and approved by Enbridge Gas's Executive Management Team. Any subsequent updates to the budget and LRP are also reviewed and approved by Enbridge Gas's Executive Management Team.

4. Capital Investment Plan

4.1 Project Selection Process

62. Enbridge Gas uses the defined asset management framework and decision-making processes (please see Exhibit 2, Tab 6, Schedule 2, Section 4.1.5) to form the basis for the selection and prioritization/optimization process for capital investments. Within the overall Asset Management Strategic Framework, as capital investment needs are identified, they are evaluated and executed through the AIPM process (please see Exhibit 2, Tab 6, Schedule 2, Section 4.3).

Customer Needs and Overall System Planning Policy Objectives

63. An important part of the asset planning process is the inclusion of customer needs and preferences into the analysis of alternatives, pacing and optimization of capital plans. The results of this customer engagement are important inputs to Enbridge Gas's investment planning activities and commitment to its customers. Enbridge

Gas conducted an extensive customer engagement process throughout 2021 and early 2022. Exhibit 2, Tab 6, Schedule 2, Section 2.4.1 provides additional information on the customer engagement results, and a description of customer engagement activities and results in further detail is provided at Exhibit 1, Tab 6, Schedule 1.

64. The customer engagement results demonstrate that customers value the safe, reliable, cost-effective, and environmentally responsible provision of natural gas. The customer engagement results also inform and reinforce Enbridge Gas's asset management decision-making framework.

Integrated Resource Planning

65. The OEB released the first-generation IRP Decision and Order[17] and its companion document the IRP Framework (collectively referred to as the 'Decision') on July 22, 2021. The Decision provided necessary policy guidance, and therefore a path forward, for Enbridge Gas to enhance its existing planning processes to assess system needs and constraints for demand and/or supply-side alternatives that may defer or avoid traditional capital infrastructure investments. With the IRP Framework, Enbridge Gas can meet system needs with an alternative solution(s) (where feasible) for new pipeline infrastructure to meet its customer energy needs safely, reliably, and affordably. Information on IRP alternative types is provided in Section 7 of the IRP Decision.[18]

66. The 2023 to 2032 AMP is the first version incorporating the IRP Framework into the Company's planning and asset management process. How the IRP Assessment

[17] EB-2020-0091.
[18] Ibid, Decision and Order, Section 7.

Process[19] was incorporated into the AMP is provided in Exhibit 2, Tab 6, Schedule 2, Section 4.3.4.1.

67. IRP capital costs are eligible for inclusion in rate base where Enbridge Gas owns and operates the IRP alternative. Where Enbridge Gas makes an enabling payment to a competitive service provider and does not own and operate the asset, these costs can be recovered as part of ongoing operational and maintenance expenses. During the current deferred rebasing term, the OEB approved an IRP Operating Costs Deferral Account and an IRP Capital Costs Deferral Account to track incremental IRP-related costs.[20]

Linkages and Trade-Offs Between Capital Projects and Ongoing O&M Spending

68. In developing the AMP, Enbridge Gas considers both capital and O&M expenditures over an asset's life cycle to ensure that optimal asset value is attained over the asset's life. Enbridge Gas will continue to evaluate and incorporate condition information, risk implications, and impacts from IRP/Energy Transition to support decision-making and the resultant capital or O&M investment. Please see Exhibit 2, Tab 6, Schedule 2, Section 4.1.3 & 4.1.5 for further details.

69. In the case of Technology & Information Services (TIS) (please see Exhibit 2, Tab 6, Schedule 2, Section 5.6), Enbridge Gas has adopted cloud computing services to reduce outages from infrastructure failures, reduce cyber-attack exposure, leverage a scalable core infrastructure, reduce delays and improve business reliability, as assets reaching end of life create material operational risk for hosted systems. In addition, on-premises licence models are no longer available within the software industry. Historically, Enbridge Gas purchased its software licences and IT

[19] EB-2020-0091, Decision and Order, Section 8.
[20] EB-2020-0091, Decision and Order, Section 15.

infrastructure systems and would capitalize and amortize the costs over time. In cloud computing, a cloud services user does not own the underlying assets, as the cloud subscription is expensed under the O&M budget. The transition to cloud computing services results in higher O&M costs (and lower capital costs) as spending shifts away from capital.

70. In general, Enbridge Gas's maintenance programs involve the O&M costs 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.

71. Enbridge Gas's Transmission Integrity Management Program (TIMP) (please see Exhibit 2, Tab 6, Schedule 2, Section 5.2.3.3) includes Capital and O&M expenditures to perform condition assessment of assets. Through this assessment, the health of the asset can be established and:
    a) the asset is confirmed to be fit for service and no further evaluation is required until the next scheduled inspection;
    b) the asset is confirmed to be fit for service with additional maintenance and inspection activities; or,
    c) the asset requires some form of replacement or renewal that will require capital investment.

72. In the case of the Distribution Integrity Management Program (DIMP) (please see Exhibit 2, Tab 6, Schedule 2, Section 5.2.3.4), direct inspection programs can be cost prohibitive or inviable as a result of the very large number of assets, the design and installation practices, and the generally smaller size of the assets. As a result, leaks on these assets are addressed both proactively and reactively through a

combination of repairs (O&M) and replacements (Capital). Proactive replacements target populations of pipe with leakage history or properties which are known to contribute to leakage and cannot be cost-effectively mitigated through other means. Statistical methods based on the leak rate in the population are used to identify specific pipelines that may be nearing end of life and prioritize them for replacement in an attempt to prevent leaks and associated consequences to operational reliability, GHG emissions, and public safety.

73. Risk is a factor in determining the appropriate time to make an investment to renew or replace an asset. Using the Risk Management processes provided in the AMP Section 4.2, 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 (AMP)

74. Enbridge Gas's engineering plan is represented by Enbridge Gas's 2023 to 2032 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 needs (risks and opportunities) related to natural gas and hydrogen carrying assets and the supporting TIS, Real Estate and Workplace Services (REWS), and Fleet assets. In the case of commodity-carrying assets, these investments are driven by an understanding of asset condition, system health and the risks associated with individual asset categories or classes. 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

75. Enbridge Gas investment categories have been provided in Table 2 in a manner that conforms 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:

a) System access investments are additions and modifications (including asset relocation) to a distributor's system that a distributor is obligated to perform to provide a customer or group of customers with access to natural gas services via the distribution system;
b) 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;
c) System service investments are modifications to a distributor's system to ensure the system continues to meet distributor operational objectives; and
d) 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[21]
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 – Class Location DP – Corrosion DP – Main Replacement DP – Service Relay DS – Gate, Feeder and A Stations DS – Inside Regulator and ERR Program DS – Station Rebuilds and B and C Stations LNG – Replacements TPS – Class Location TPS – Improvements TPS – Replacements UTIL – Meters (mtc) UTIL – Regulator Refit UTIL – Remediation
System Service	CS – Integrity DP – Damage Prevention DP – Integrity DP – MOP DS – Integrity Initiatives GTH – System Reinforcement LNG – Improvements LNG – Integrity

[21] CC = Customer Connections, DP = Distribution Pipe, DS = Distribution Stations, GTH = Growth, LNG = Liquified Natural Gas, REWS = Real Estate & Workplace Services, TIS = Technology & Information Services, TPS = Transmission Pipe & Underground Storage, UTIL = Utilization

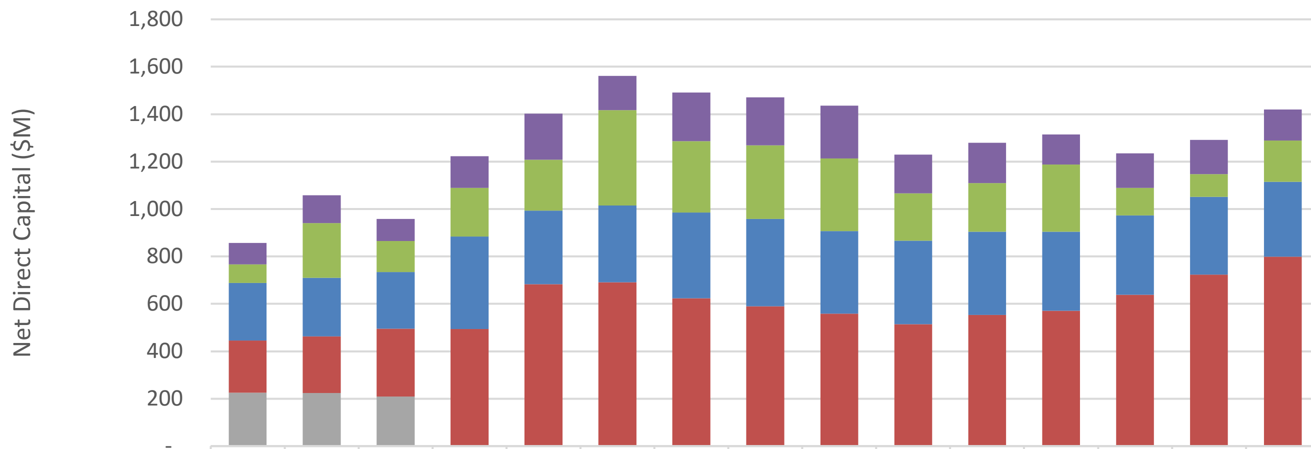
USP Category	Asset Program[21]
	TPS – Integrity UTIL – Integrity Survey UTIL – Monitoring Systems
General Plant	CS – Land/Structures - Improvements FLEET – Equipment and Materials FLEET – Tools FLEET – Vehicles LNG – Land/Structures - Improvements REWS – Furniture/Structures and Improvements TIS – Business Solutions TIS – Infrastructure TPS – Land/Structures - Improvements

4.4 Capital Expenditure Summary

76. Enbridge Gas's total historical and total forecasted 10-year spend profile by investment category is provided in Figure 6. Enbridge Gas's projected spend totals $6.9 billion from 2024 to 2028 and $13.7 billion from 2023 to 2032; the projected /u annual spend ranges between $1.2 billion to $1.6 billion from 2023 to 2032. System Renewal and System Access are Enbridge Gas's highest asset investment categories at $2.8 billion and $1.8 billion from 2024 to 2028, 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.

77. The capital expenditure is the result of applying Enbridge Gas's asset management decision-making strategies and framework to balance risk, cost and performance throughout the asset life cycle (please see Exhibit 2, Tab 6, Schedule 2, Section 4.1.5).

Figure 6: Enbridge Gas's Capital Expenditures /u



	2018A	2019A	2020A	2021A	2022F	2023F	2024F	2025F	2026F	2027F	2028F	2029F	2030F	2031F	2032F
General Plant	91	117	93	134	195	145	205	202	222	163	169	128	146	146	131
System Service	78	231	130	205	214	403	301	311	306	200	206	284	116	95	175
System Access	242	246	238	391	311	323	362	369	349	353	350	332	335	327	315
System Renewal	220	239	287	494	683	691	623	589	559	514	554	571	639	724	799
Overhead	226	225	209	-	-	-	-	-	-	-	-	-	-	-	-
Grand Total	857	1,058	958	1,223	1,403	1,562	1,491	1,471	1,436	1,229	1,279	1,315	1,235	1,292	1,420

Note: Overheads are included in the Investment Categories starting in 2021.

5. Asset Management Plan

78. The 2023 to 2032 Enbridge Gas AMP has been filed separately as part of this Enbridge Gas USP and provided at Exhibit 2, Tab 6, Schedule 2.

5.1 Description of Plan

79. The AMP outlines Enbridge Gas's asset management policies and strategies, processes and governance; asset class objectives and life-cycle strategies; asset inventory, condition methodology and findings; risks, opportunities and strategies; and the 10-year capital plan. Asset Management at Enbridge Gas ensures that value is realized through its assets while managing risk and opportunity.

Scope

80. The AMP includes all regulated assets inclusive of commodity-carrying assets directly related to the task of transporting natural gas and low-carbon fuels from the source to the end-use customer, as well as assets that support business operations. The asset classes used to organize and define Enbridge Gas's assets 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 & Information Services.

5.2 Alignment of Asset Management Plan to the Chapter 5 Requirements

81. The AMP was built using guidance from the OEB's Filing Requirements for Natural Gas Rate Applications (the Filing Requirements)[22]. Further guidance was obtained through the more detailed Chapter 5 of the Filing Requirements for Electricity Distributor Applications[23]. Table 3 provides the alignment of sections of Enbridge Gas's AMP to the Chapter 5 requirements.

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

Table 3

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

Chapter 5 - Filing Requirements (OEB)	EGI 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 3: Asset Management Strategic Framework Section 3.2: EGI Integration and Continual Improvement Section 4.2.5: Monitor and Review Risk Section 4.3.6 AIPM Performance Review
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 and Assets (by asset class)
5.3.3 Asset lifecycle optimization policies and practices	Section 4.1.3 Life Cycle Delivery Section 5: Customers and Assets (by asset class)
5.3.4 System capability assessment for renewable energy generation	Section 3.3: Energy Transition
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 and Assets (by asset class) Section 6: Summary of Capital Expenditure

5.3 Potential ICM Projects

82. Table 4 shows investments with total in-service capital that exceeds $50 million that meet the ICM-eligible criteria for materiality, need and prudence. Based on the 2023 to 2032 capital expenditure forecast (please see Figure 7), Enbridge Gas does not anticipate seeking ICM recovery for these projects.

Table 4

Potential ICM Projects: EGI

Asset Class (EGI)	**USP Investment Category**	**Investment Name**	**In-Service Date**	**(2023 to 2032) Forecast**[24] ($ millions)	**In-Service Capital** ($ millions)
Compression Stations	System Renewal	Dawn C Compression Lifecycle	2026	$163.4	$146.1
Growth	System Service	Hamilton Industrial Reinforcement	2025	$132.9	$126.4
Distribution Pipe	System Renewal	A:10 Wilson Avenue, Toronto, VSM Replacement	2025	$91.2	$91.5
Transmission Pipe & Underground Storage	System Access	Dawn to Parkway Expansion Project - Kirkwall-Hamilton NPS 48	2026	$245.9	$228.2
Transmission Pipe & Underground Storage	System Access	PREP: NPS 36 Looping to Comber Transmission	2028	$95.9	$86.4
Real Estate & Workplace Services	General Plant	New London Site	2026	$51.9	$55.1
Technology and Information Services	General Plant	Contract Market Systems – Technology Obsolescence	2026	$68.4	$68.4

[24] Includes overhead allocation

83. The discrete projects provided in Table 4 are driven by asset class strategies and, depending on the materiality threshold in the year in which they go into service, may not be supported by existing rates. Total incremental spend includes all capital costs associated with the identified project incurred up to the project's in-service year when ICM is requested. For eligible projects, the IRP Assessment process is used to evaluate the feasibility of IRPAs, which could impact the investment timing and scope.

84. Using the capital expenditure summary provided in Section 4, the total in-service capital required for identified ICM projects between the years 2019 and 2022 is illustrated by the hatched bars; all other spend is represented as part of the appropriate investment category (please see Figure 7).[25] As shown in Figure 7, Enbridge Gas is not applying for ICM funding as part of 2023 Rates and is not anticipating applying for ICM treatment in the 2024 to 2028 forecast years. In the event of a change to the capital expenditure forecast that would trigger an ICM request, the ICM eligibility in the 2025 to 2028 forecast years would be assessed pending materiality threshold calculations. For more details regarding the condition and strategies driving the need for these projects requiring significant investment, please see Exhibit 2, Tab 6, Schedule 2.

[25] ICM project spend in Figure 7 represents the total in-service capital required for the project (including Overheads), compared to Figure 6 in Section 4.4 where the capital expenditure profile represents the annual cash flow (which includes required preliminary and post spend for ICM projects).

Figure 7: Enbridge Gas's Capital Expenditure Summary (with proposed ICM project in-service spend identified from 2019 – 2022)

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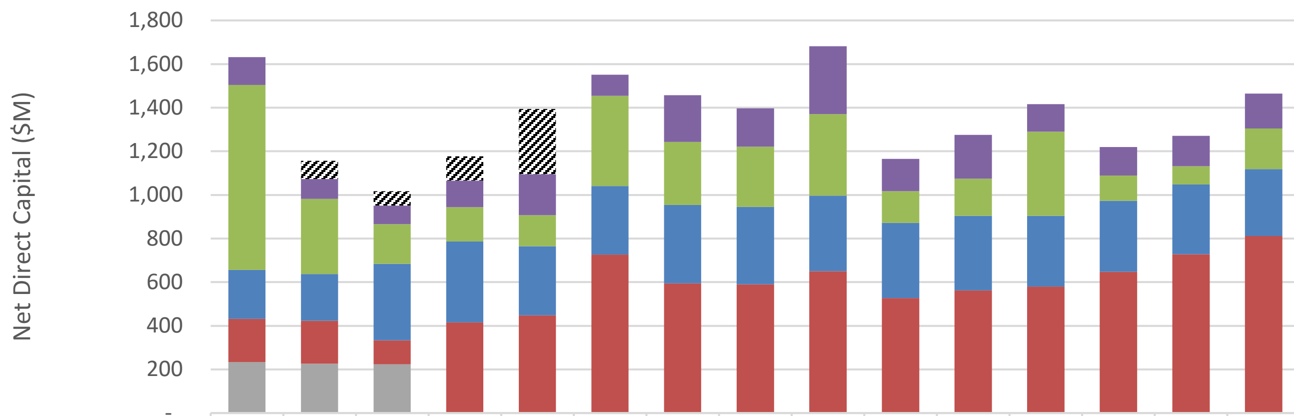

	2018A	2019A	2020A	2021A	2022F	2023F	2024F	2025F	2026F	2027F	2028F	2029F	2030F	2031F	2032F
ICM Projects	-	84	66	111	299				-	-					
General Plant	128	91	85	122	188	96	213	176	311	149	202	127	130	139	159
System Service	848	345	182	157	142	414	289	274	375	145	169	386	115	84	186
System Access	224	213	350	371	317	313	360	355	346	345	342	324	326	319	307
System Renewal	199	196	111	416	448	727	595	591	650	528	562	580	647	728	812
Overhead	233	227	223	-		-	-	-	-	-					
Grand Total	1,631	1,157	1,017	1,177	1,394	1,551	1,457	1,397	1,682	1,166	1,275	1,417	1,219	1,271	1,464

Notes:

1. Overheads are included in USP categories starting in 2021

6. Continuous Improvements and Benchmarking

85. Enbridge Gas continues to seek opportunities to build continuous improvements into its planning processes, goals and objectives. Our strategic priorities guide decision making and continue to support streamlining our operations and optimizing our distribution, storage, and transmission assets. Examples of opportunities anticipated over the 2024 to 2028 IR term include organizational alignment within Enbridge Gas's regional construction teams, productivity gains in alliance partner agreements and real estate optimization. Enbridge Gas will also apply the Plan-Do-

Check-Act quality cycle to continuously find and pursue improvement opportunities over 2024 to 2028 while continuing to establish and realize new savings opportunities, please see Exhibit 2, Tab 6, Schedule 2, Section 3, page 27 for more detail on the Plan-Do-Check-Act Cycle. It is premature to quantify the degree of benefits which may be realized.

86. Another way Enbridge Gas has 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.

87. Enbridge Gas participates in compensation market reviews (please see Exhibit 4, Tab 4, Schedule 3, Attachment 1) and pension and benefit benchmarking (please see Exhibit 4, Tab 4, Schedule 3, Attachment 2) to enable competitive market analysis and the identification of prevailing compensation, benefits and pension practices and design trends. Targeting a median market position is a reasonable and prevalent approach required to attract and retain a workforce qualified to execute Enbridge Gas's business objectives including providing safe and reliable service to Enbridge Gas's customers.

88. Cost benchmarking results from the Black & Veatch Management Consulting study titled "Total Factor Productivity, Benchmarking, And Recommended Inflation and X Factors for Enbridge Gas Inc. Incentive Rate-Setting Mechanism" indicate that

Enbridge Gas is a very good cost performer and therefore has less potential to achieve efficiency gains than much of the rest of the gas distribution industry. This study is provided at Exhibit 10, Tab 1, Schedule 1, Attachment 1.

7. Other

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

89. 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:
    a) The proposed hydrocarbon pipeline is more than 20 km in length;
    b) Is projected to cost more than the amount prescribed by the regulations (presently $2 million);
    c) 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,
    d) Criteria prescribed by the regulations are met 2003, c.3, s. 63(1).

90. Table 5 lists the investments that have been identified as subject to LTC in 2024, overhead allocations are included in the forecast costs. This investment list is subject to change as projects are identified within programs and as the scope and cost of investments are further refined.

Table 5: 2024 Investments Subject to LTC

Asset Class	Investment Code	Investment Name	2024 Forecast	2023 to 2032 Forecast
Distribution Pipe	10290	St. Laurent Phase 3 - Coventry/Cummings/St. Laurent (Plastic)	$10,971,063	$11,273,059
Distribution Pipe	10293	St. Laurent Phase 3 - North/South (NPS12/16 Steel)	$56,123,791	$59,372,892

Asset Class	Investment Code	Investment Name	2024 Forecast	2023 to 2032 Forecast
Distribution Pipe	100295	NPS 8 Port Stanley Replacement	$18,457,580	$19,067,429
Growth	30500	NW 2103 Dundalk XHP Reinforcement SRP	$6,919,435	$6,919,435
Growth	30507	SRP_LUG East_Kingston_28401002STN & Reinforcement_NPS12_1000m_1210kPa	$6,217,387	$6,217,387
Growth	30518	SRP_LUG East_Picton_28103006STN_Rebuild	$3,011,803	$3,011,803
Growth	30525	SRP_North_Timmins_Hwy 655_Reinforcement_NPS6_850m_6895kPa	$2,050,589	$2,050,589
Growth	30566	SRP_Southwest_Woodstock_Reinforcement & Reinforcement_NPS6_8200m_1900kPa	$11,662,726	$11,662,726
Growth	100703	SRP_LUG East Kingston_Creekford Rd_Reinforcement_NPS8_6200m_6895kPa	$24,094,424	$28,702,886
Growth	736075	WIND: Wheatley-1B - Panhandle Distribution Reinforcement - Wheatley Lateral Replacement and Reinforcement	$19,941,981	$21,106,551
Growth	736259	Hamilton Industrial Reinforcement	$10,252,946	$132,907,739
Compression Stations	100901	Dawn to Corunna	$6,418,838	$165,101,440
Transmission Pipe & Underground Storage	48654	Dawn Parkway Expansion Project (Kirkwall-Hamilton NPS 48)	$24,350,748	$245,855,289
Transmission Pipe & Underground Storage	49758	Panhandle Regional Expansion Project	$11,012,395	$219,431,846
Transmission Pipe & Underground Storage	736923	Panhandle Regional Expansion Project - Leamington Interconnect	$50,750,549	$69,934,844

91. For investments greater than $10 million that are subject to an LTC in the 10-year AMP, please see Exhibit 2, Tab 6, Schedule 2, Appendix A.

7.2 Projects/Programs Not Subject to Leave to Construct

92. Construction projects may not require leave from the OEB prior to construction in the following circumstances:
   a) The project does not meet the leave to construct criteria prescribed in the *OEB Act*;
   b) The project falls under federal jurisdiction that requires approval from the Canada Energy Regulator; or,
   c) The project involves relocation or reconstruction of an existing pipeline unless the size of the line is changed or additional land is required.

93. Table 6 lists the investments that have been identified in 2024 as not subject to LTC, overhead allocations are included in the forecast costs.

Table 6: 2024 Investments Not Subject to LTC

Asset Class	Investment Code	Investment Name	2024 Forecast	2023 to 2032 Forecast
Distribution Pipe	7660	VPM - Erin Township	$3,032,186	$11,695,807
Distribution Pipe	100339	A10: Wilson Avenue, Toronto, VSM Replacement	$36,134,725	$91,158,784
Distribution Pipe	100517	Oshawa LP Replacement Phase 1 Olive Ave	$2,133,623	$4,209,858
Distribution Pipe	101343	A60: Sparks St, Ottawa, Replacement	$11,236,154	$11,808,967
Distribution Stations	1011	SCHOMBERG GATE	$4,100,406	$4,175,221
Distribution Stations	3605	BAYVIEW FEEDER	$5,908,922	$6,532,378
Distribution Stations	7752	NIAGARA GATE	$3,523,787	$4,550,640
Distribution Stations	7756	RUGBY GATE	$2,336,960	$3,191,800

Asset Class	Investment Code	Investment Name	2024 Forecast	2023 to 2032 Forecast
Distribution Stations	7758	THORNTON GATE	$3,908,199	$4,656,346
Distribution Stations	48743	Distribution Operations Station Maintenance Blankets	$2,141,465	$21,900,914
Distribution Stations	48744	Distribution Operations Station Painting	$2,563,237	$26,848,160
Distribution Stations	100918	TBAY: 33-23-700 Arthur St TBS, Thunder Bay, Station Rebuild	$2,563,237	$2,563,237
Distribution Stations	101086	HAMI-Hamilton Gate 3	$4,767,620	$8,550,131
Distribution Stations	501374	2024 Fire Suppression and Auto Transfer Generator	$2,509,409	$2,509,409
Distribution Stations	503332	WIND - 06B-403 California Ave station rebuild	$4,101,179	$4,101,179
Distribution Stations	503369	Lisgar Station	$2,337,155	$21,527,376
Distribution Stations	734674	LOND: 14O-503R Highbury and Cheapside Dist Stn	$8,586,843	$9,583,267
Distribution Stations	734689	LOND: 14R-104 Beachville Domtar Trans Stn	$8,458,681	$8,458,681
Growth	736975	Enbridge Gas Distribution System Hydrogen Feasibility Study	$5,125,507	$15,523,163
Compression Stations	48715	Dawn C Compression Lifecycle	$15,994,596	$163,382,650
Compression Stations	733780	Dawn D Gas Generator - Mid life Overhaul	$2,772,130	$2,772,130
Transmission Pipe & Underground Storage	6377	PCRW:Wells-Upgrade	$2,242,409	$12,841,157
Transmission Pipe & Underground Storage	13044	PSEC:TS22H Well-Install	$2,428,210.42	$3,182,592
Transmission Pipe & Underground Storage	13047	PSEC:TS23H Well-Install	$2,428,210.42	$3,182,592

Asset Class	Investment Code	Investment Name	2024 Forecast	2023 to 2032 Forecast
Transmission Pipe & Underground Storage	100086	Panhandle Line Replacement	$31,089,061	$37,488,223
Transmission Pipe & Underground Storage	503024	2024 Waubuno 2 replacement wells	$5,086,743	$5,322,148
Real Estate & Workplace Services	3640	Station B New Building	$11,532,392	$36,470,620
Real Estate & Workplace Services	3642	SMOC/Coventry Facility Consolidation	$6,406,884	$20,122,910
Real Estate & Workplace Services	501813	Kennedy Road Expansion	$25,307,193	$48,870,149
TIS	102291	Contract Market Harmonization	$6,406,884	$18,968,576
TIS	102364	Records Management Upgrade (2024-2027)	$5,445,852	$27,930,782
TIS	736081	General Service Rebasing Changes	$17,939,276	$20,522,746
TIS	736942	Contract Market Systems - Technology Obsolescence	$22,846,949	$68,414,861
TIS	737248	AWS Phase3	$2,819,029	$2,819,029

7.3 Customer Additions and Profitability Index Values

Customer Connections Feasibility

94. 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 E.B.O 188 report.[26] The intent of E.B.O 188 is to facilitate rational expansion of natural gas service while protecting existing customers from undue cross-subsidization.

[26] E.B.O 188 Final Report of the Board, January 30, 1998.

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

96. If the expansion is driven by large commercial/industrial customers (contract market), the feasibility analysis factors in the incremental cost and revenue of the customers on the project and determines whether the customers would be required to pay a Contribution in Aid of Construction (CIAC). This is explained in more detail in the Feasibility Process below.

Investment Portfolio

97. 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 is designed by including 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)

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

Feasibility Process

99. When assessing the feasibility of a new project, Enbridge Gas prepares a forecast of project costs and revenues for calculating Profitability Index (PI) using the formula below.[27]

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

100. When the present value (PV) of revenues is greater or equal to the PV of project costs, the project PI will be greater or equal to 1.0 and makes the project economically feasible. A PI greater or equal to 1.0 means that the revenue recovers the entire cost of the project over its life and the project can be built at no cost to the customer. Depending on the size and scope of a project, Enbridge Gas may be required to submit an LTC application for OEB approval. In approving an LTC application, the OEB may require that Enbridge Gas meet certain conditions.

101. When the present value of revenues is less than the present value of costs, customers will be asked to pay a CIAC to recover the revenue shortfall. The CIAC is the amount of contribution required from the customer to make the project feasible (i.e., to achieve the required PI threshold).

102. In lieu of CIAC, the customer may be given an option to pay a System Expansion Surcharge (SES) or Temporary Connection Surcharge (TCS) to compensate for the revenue shortfall. The OEB-approved SES and TCS are volumetric charges[28] at $0.23/m^3. TCS and SES are charged on top of the normal distribution rates for a fixed term that is determined by feasibility calculations.

---

[27] PI formula is provided in The Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario, EBO 188 (January 30, 1998).
[28] EB-2020-0094, Decision and Order, November 5, 2020.

103. The amount charged as a lump sum CIAC or SES/TCS revenue paid over a certain term is project-specific and varies depending on the costs and revenues for each project. The OEB has established feasibility guidelines and rules for calculating the CIAC and TCS/SES terms. Utilities can only charge a CIAC or SES/TCS per methodologies approved by the OEB[29]. If the customer chooses not to pay, the project is not built.

Benefits

104. 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

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

106. Indirect costs for a project may include the cost of the groups who support connecting new customers (e.g., Customer Connections) and the amortized cost of system reinforcement projects undertaken in the past.

Process for Connecting Residential Infill Customers

107. Residential infills are attached using the Extra Length Rule. This rule assumes that standard residential services are feasible to a certain threshold of length that is 20 metres and are attached at no cost to the customer. Any service beyond 20 metres

[29] E.B.O. 188, The Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario, January 30, 1998, and EB-2020-0094, Decision and Order, November 5, 2020.

is subject to an extra length charge at rates prescribed in Rider G of the Enbridge Gas Rate Handbook, provided at Exhibit 8, Tab 3, Schedule 1, Attachment 1. The length of the service will be measured from the customer's property line to the location where the gas meter is installed. The extra length criteria is as follows:

a) Extra Length Charge: Beginning in the 2024 Test Year the extra length charge is proposed to be $122 per metre beyond the free service allowance of 20 metres. Further details on the update to this rate are provided at Exhibit 8, Tab 3, Schedule 1. The previous rates were $32 per metre in the EGD rate zone and $45 per metre in Union rate zones; and
b) Minimum Load: There is no minimum load required for residential infill customers to qualify for the free service allowance of 20 metres.

Customer Additions Forecast

108. The customer additions 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.

109. Further detail on the Customer Additions forecast is provided in Exhibit 2, Tab 6, Schedule 2, Section 5.1.4.

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

110. 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.

111. In 2016, the OEB issued a decision in its generic proceeding on new community expansion[30] which indicated that incumbent utilities could propose an 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. Community expansion projects, which employ an SES, are also subject to a 10-year rate stability period, during which the utility is to bear the risk of its customer attachment forecast and revenue requirement.

112. 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.

113. 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.

114. To determine which communities will be qualified for gas service expansions, the company assesses the economic feasibility for potential expansion projects within communities expressing interest in gas service expansion (using the same process used for the PI calculation). Many of these community expansion projects will still require the OEB's approval (where LTC approvals are required). Community expansion projects are categorized under the System Access category of projects.

[30] EB-2016-0004, OEB Decision and Order, November 17, 2016.

For further details on the large community expansion projects reflected in the forecast, please see Exhibit 2, Tab 6, Schedule 2, Section 5.1.9.3.

115. Enbridge Gas has several community expansion projects, completed or underway, made possible through phase one of the Natural Gas Expansion Program, which was announced in March 2019 with allocated funding of approximately $56 million. These projects include bringing natural gas to the communities of Chippewas of the Thames First Nation, North Bay-Northshore and Peninsula Roads, Saugeen First Nation, Cornwall Island, Hiawatha First Nation, Scugog Island, and rural areas around Chatham-Kent.

116. Enbridge Gas brought natural gas to Fenelon Falls and Moraviantown First Nation, which was made possible with funding provided by the Ontario Government's previous Natural Gas Grant Program.

117. 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.

118. In December 2019, the Ontario Government announced it is continuing to expand access to safe, reliable, and affordable natural gas to rural, northern and Indigenous communities. As part of the announcement, the Ministry of Energy (MOE) sent a letter to every mayor in Ontario advising them of the Natural Gas Expansion Program.

119. Enbridge Gas submitted a number of project proposals to the OEB prior to the submission deadline of August 4, 2020. In total, Enbridge Gas submitted 203

Community Expansion project proposals and four Economic Development proposed projects.

120. The OEB evaluated these proposals and submitted its report to the MOE by October 31, 2020. The MOE reviewed the OEB's report and used it as an input to make project selections.

121. In June 2021, Ontario's Natural Gas Expansion Program allocated approximately $234 million in funding to support new natural gas expansion projects, this was a $104 million increase from the original $130 million funding amount.

122. Enbridge Gas is working to deliver the selected projects with varying construction start dates, with all starting by 2025. In Spring 2022, Enbridge Gas initiated construction on two of the selected projects: (1) Perth East (Brunner) and (2) Stanley's Old Maple Lane Farm (City of Ottawa: York's Corners Rd.). In addition, Enbridge Gas is working on a number of consultation efforts for upcoming projects.

EGI Asset Management Plan 2023 – 2032

October 31, 2022

Report

Company: Enbridge Gas Inc.

Owned by: Asset Management Department

Controlled Location: Asset Management TeamSite

EGI Asset Management Plan 2023 – 2032

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EGI Asset Management Plan 2023 – 2032

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1 Executive Summary

1.1 Document Purpose

On January 1, 2019, Enbridge Gas Distribution (EGD) and Union Gas Limited (Union) 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 3.8 million residential, commercial and industrial connections in Ontario, serving over 313 municipalities and 23 First Nation communities. EGI's 180 billion cubic feet (approximately five billion cubic metres) of regulated 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 assets is important for the secure, safe and reliable delivery of energy 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
- How Enbridge strategies and stakeholder commitments (**Section 2.4**) are linked to asset class strategies
- Process and governance for asset management planning including linkages to EGI's processes for managing risk
- The approach to Integrated Resource Planning (IRP) and provide EGI's IRP Binary Screening and associated IRP alternative (IRPA) evaluation by project (Appendix B)
- Asset class objectives and life cycle management strategies
- Asset inventory, condition methodology, condition findings, risks, opportunities and renewal strategies
- Optimized 10-year capital plan required to manage assets from 2023 to 2032

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 expectations of the Ontario Energy Board (OEB) as set out in the *Handbook for Utility Rate Applications, October 13, 2016* and the *Filing Requirements for Natural Gas Rate Applications, February 16, 2017* and EB-2020-0091 Enbridge Gas Inc. *Integrated Resource Planning Proposal, July 22, 2021.*

1.2 Overview of the Asset Management Plan

EGI's AMP includes all regulated assets inclusive of commodity-carrying assets directly related to the task of transporting natural gas and hydrogen from the source to the end-use customer, as well as assets that support business operations. The asset classes used to organize and define EGI's assets 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.

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 identified and implemented.

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

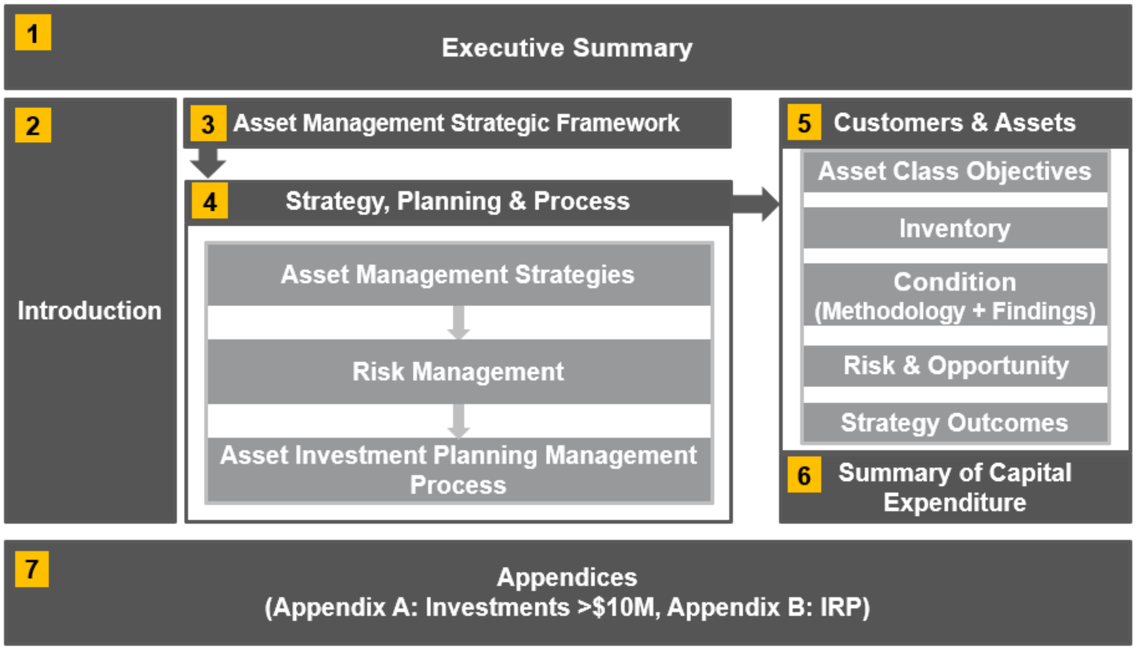

Figure 1.2-1: EGI's Asset Management Plan Structure

Executive Summary (Section 1): This section provides a summary of the Asset Management Plan.

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, Energy Transition, IRP, and the structure of the document.

Strategy, Planning and Process (Section 4): This section details the alignment of asset management at EGI with the Enbridge strategic priorities and includes EGI's asset management strategies, risk management and the Asset Investment Planning and Management (AIPM) process.

Customers and Assets (Section 5): This section details the following:

- EGI's customers and the customer growth projections
- Asset class objectives
- Asset class strategies
- 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 10-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 10-year portfolio of spend.

Appendices (Section 7): The appendices present supporting information for the Asset Management Plan. Appendix A includes descriptions of discrete investments with a Net Base Capex greater than $10M in 2023 to 2032. Appendix B contains the IRP Binary Screening and associated IRPA evaluation statuses by project.

1.3 Advancing Asset Management

This document reflects the integrated utility's Asset Management Plan for the next 10 years, with assets for the rate zones (the EGD and Union North and South rate zones) being maintained separately for capital planning purposes in 2023 and as EGI from 2024 through to the end of 2032.

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

- **Energy Transition**
  This AMP incorporates assumptions for customer additions, peak hour demand and peak day demand, each of which have been adjusted to reflect EGI's current view of the impacts of the Energy Transition (Exhibit 1, Tab 10, Schedule 4). EGI acknowledges that energy transition is evolving and that investment decisions will be based on the best information at the time, including consideration of IESO's forecast electricity demand. EGI maintains its obligation to serve and is committed to implementing IRP with the intent of evaluating and comparing both supply-side and demand-side options to meet an energy system need in the immediate, medium and longer term.

- **Integrated Resource Planning (IRP)**
  IRP represents a significant change to the facility planning that EGI has performed in the past and, as such, EGI is taking steps to develop processes, resources and capabilities to integrate new IRP requirements into its existing asset management process and other processes. EGI's AIPM process now incorporates the IRP assessment process. The IRP assessment step of the AIPM process (see **Section 4.3.4.1**), determines if an IRPA evaluation is required for each system need, and, if so, a cost-effective IRPA exists. Further details on the IRP assessment process can be found in EGI's IRP Annual Report.

  Through the IRP assessment process, EGI has performed IRP Binary Screenings on eligible projects, consistent with the guidance provided by the OEB in its Decision. The IRP Binary Screening results and the associated IRPA evaluation statuses, by project, can be found in the **Appendix B – IRP**.

- **Alignment with Enbridge Inc.'s 2022 Enbridge Strategic Priorities**

  Enbridge Inc. published a revised Strategic Plan in 2022. 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**.

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

  The phase two Boundary and Real Estate initiative has been completed. EGI's regional boundaries and real estate assets across the province were reviewed to align current boundaries and strategically locate EGI's operating depots. The second phase of the initiative evaluated the area between the GTA West and Southeast regions. In January 2022, the regional borders were realigned to optimize the facilities within each new region.

- **Consolidation of asset data**

  The systems of record for asset data in the Union rate zones include Maximo for meter, work, damage and condition data; SAP-PM for station work and asset data; GIS for pipe data; and CORR for corrosion data. Some data that supports the Asset Management Plan is now being migrated to a datamart as part of the integration of work and asset management systems. Ongoing documentation and consolidation of these datasets will enable EGI to analyze inventories more efficiently for the combined utility and better support the Integrity and Asset Management functions.

- **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
  - Mapping the capital expenditures presented in **Section 5** to the asset class strategy
  - Identification of outstanding items that remain in legacy programs until they can be integrated

- **Integration items to highlight**

  Standards for installation, inspection, operation, maintenance, and asset decommissioning continue to be integrated. This work is ongoing; some legacy practices continue to be followed for each rate zone as analysis deemed it as appropriate for the assets at this time. Other design changes may be implemented on a go-forward basis. These new standards are reflected in this Asset Management Plan and will continue to evolve throughout the integration process. Specific integration efforts include:

  - **Integrity Management Program**

    EGI continues to evolve its Integrity Management Program based upon industry best practices and incident learnings. EGI has developed a quantitative risk model to assess the primary risk for pipeline assets within the distribution system which is being leveraged to identify and prioritize assets that are approaching end of life and need to be replaced. Transmission pipeline assets already have a quantitative risk model; however, that model has also been enhanced with additional hazards and consequences, as well as the development of Safety Targets to further assess the risk of Transmission Integrity Management Program (TIMP) assets.

Detailed documented assessments (i.e., Integrity Plans) for assets or assets groups are being created to ensure the following:

- All potential hazards are considered.
- Appropriate inspection methods and timing are determined.
- Inspections are completed.
- Results are assessed.
- Any required repairs are made.
- The fitness for continued service is confirmed.

EGI has introduced the use of Safety Cases as an independent check that all hazards have been effectively considered and addressed. Safety Cases will initially be developed for a subset of the TIMP assets and expanded to other assets over time.

- **Fleet and Equipment**
  EGI continues to standardize processes and procedures related to the assignment of vehicles for the appropriate roles, types of vehicles required to support employees in performing their roles, and vehicle maintenance and repair model.

- **Technology and Information Services**
  TIS continues to support process and system integration while in parallel reducing EGI operational and cybersecurity risks. EGI continues to align systems, processes and procedures, prioritized based on business value (efficiency, safety/reliability, compliance) while adopting industry best practices regarding cloud computing where feasible.

- **Modelling enhancements from Distribution Optimization Engineering**
  EGI has harmonized its approach to degree day forecasting and system modelling for growth; the resultant facility requirements form the basis for reinforcement forecast in this Asset Management Plan.

- **Operationalizing the Asset Plan**

  As EGI develops the maturity of its Asset Management practice, greater focus is placed on measuring delivered work relative to planned work, highlighting the need for multi-year planning and the identification of resources required to execute the plan, including the resources required to scope, plan and obtain required approvals. Accomplishments of this initiative include:

  - Documented and communicated Asset Investment Planning and Management (AIPM) processes, procedures, and accountabilities.
  - Improved communication and training to promote consistency.
  - Identification of incremental resources to support delivery of the asset investment plan.

- **10-Year Asset Management Plan**

  This version of EGI's AMP considers a ten-year horizon with the understanding that the scope of investments in the earlier years of the plan are more refined than those in later years. Considering a 10-year window allows time to consider and develop feasible IRPAs to meet the identified system needs.

- **Value Assessment Quality Assurance Approach**

  As the application of the Copperleaf value framework evolves, EGI has developed a continual improvement approach to validate and calibrate investment data, capture best practices, and to maximize value in the AMP. Emphasis was placed on applying data analytics practices and sense-checking investment data to better understand how EGI's value assessment processes are working and how they can be improved. Implementing this approach led to:

  - Increased support for Asset Management optimization and calibration activities to ensure consistency and alignment of investment data.
  - Greater stakeholder engagement and transparency of value across EGI's portfolio of opportunities.
  - Identification and documentation of improvements to the Copperleaf value framework.

- **Greenhouse gas emission reductions**

Enbridge continues to evaluate and implement facility emission reduction opportunities by ensuring initiatives effectively balance security, safety, operational reliability, customer preferences, compliance obligations and anticipated future regulations. In the evaluation of system expansion alternatives, the cost of fuel and carbon are considered along with operational requirements. These opportunities are tracked through the GHG Scope 1 & 2 Working Group. The GHG Scope 1 & 2 Working Group will identify and review potential opportunities and strategies to achieve cost-effective GHG reductions, which are incorporated into asset class life cycle strategies, as well as operating practices, equipment modernization and innovation, and emerging policies and regulations. EGI's efforts in reducing its environmental footprint are closely tied to the work outlined in this Asset Management Plan.

1.4 Capital Expenditure

The EGI capital plan was optimized from 2023 to 2032 using the Asset Investment Planning and Management (AIPM) process (outlined in **Section 4.3**). EGI's AIPM process uses Copperleaf as the asset investment planning tool. The result addresses the organization's asset needs and includes known risks and opportunities requiring action over the next ten years.

In total, 1,500 EGD RZ investments and 1,1901 Union rate zone (RZ) investments were included in the optimization of the 10-year plan. 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:
    - Exceeding an established risk threshold
    - Third-party relocation
    - Program work with sufficient history and risk to warrant continuation
    - Projects that meet the economic feasibility tests in EBO 188 and EBO 134
    - Compliance requirements
    - Investments that were already executing with costs continuing into 2023 to 2032 and the remaining work could not be shifted.

1.4.1 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 asset needs and financial considerations. Determining the capital constraint involves EGI's Asset Management, Finance and Regulatory departments. To complete EGI's latest portfolio optimization, EGI considered optimization constraints for 2023 and for the remainder of the 10-year plan separately.

For 2023, the assets for EGD RZ and Union North and South RZs, were maintained separately for capital planning purposes as 2023 is the final year of the approved five-year (2019 to 2023) deferred rebasing term from the MAADS Decision (*EB-2017-0306/EB-2017-0307*). For the 2024 to 2032 optimization constraint, EGI considered historical spend levels, inflation, smoothing the impact to ratepayers and the capital to meet asset class strategy needs.

EGI's optimization constraints were determined through the following efforts:

- For 2023, EGI recognized that two significant projects are expected to go into service in that year - Dawn to Corunna Project (see **Appendix A, Pg. 1**) and the Panhandle Regional Expansion Project (see **Appendix A, Pg. 55**). EGI first attempted to leverage the materiality threshold as the constraint for 2023 but was unable to accommodate the significant volume of compliance, must-do, and in-flight work. In the end, the 2023 Budget was constrained to $1.5B, the amount that had previously been included in the long-range plan created in 2022.
- To set a constraint for the remainder of the 10-year plan, EGI looked at scenarios between the 2023 Materiality Threshold of ~1.4B and the historical average spend of ~$1.17B[1]. In each case an escalation of 2% for inflation was

[1] Historical average spend was calculated using the average of the 2019-2021 actuals and 2022 forecast.

applied (see **Table 1.5-1** for inflation assumptions). Through the process of moving the optimization constraint line downwards from $1.4B to $1.1B, EGI examined:

- Implications to asset class strategies
- Implications to in-service capital (as a proxy for impact to ratepayers)
- Implications for the management of identified risk
- Ability to complete mandatory work
- Ability to complete work that supports the energy transition
- Ability to complete work that is in keeping with customers' stated preferences
- Organizational capacity to complete work

Through consultation with a wide range of internal stakeholders, EGI determined that the 2024-2032 optimization constraint of $1.2B with an annual escalation of 2% for inflation allowed for safe and reliable outcomes through execution of EGI's asset class strategies. EGI had to treat specific significant investments (Dawn C Compression Lifecycle in 2026 [see **Appendix A, Pg. 3**] and Dawn-Parkway Expansion [Dawn-Enniskillen NPS 48] in 2029 [see **Appendix A, Pg, 53**]) as exceptions to the optimization constraint in order to obtain the optimized result in those years.

The increase in capital for 2024 relative to the historical average is attributed to the following:

- +$129M in market driven growth with several large growth investments identified with spend in 2024 including: Panhandle Regional Expansion Project (PREP), PREP: Leamington Interconnect, Wheatley 1B PREP Reinforcement, East Kingston Creekford Road Reinforcement and the Dawn Parkway Expansion Project (Kirkwall-Hamilton NPS 48). The timing for these investments is based on the market requirements, EGI will evaluate the market driven investments for technically and economically feasible IRPAs.
- +$107M in planned replacements have shifted into 2024 to provide additional time for EGI to assess and adequately demonstrate the condition of the pipelines as an outcome of the St. Laurent LTC Decision.
- +$95M in compliance related investments including increases to meter and regulator exchanges due to increased costs for meters and large numbers of meters reaching expected end of seal life. In addition, updated hazard assessments completed under EGI's Transmission Integrity Management Program have identified the need to review and mitigate high and moderate uncertainties in the fitness-for-service conclusions of the review.

Optimization constraints lower than $1.2B (i.e., $1.1B) caused the optimization to fail as they do not accommodate all investments with fixed timing. Examples of investments with fixed timing that must be executed in a given year include:

- Compliance work must be completed in accordance with rules and regulations, deferring this work could result in EGI being out of compliance.
- Relocations must be completed in a given year order to ensure that the work triggering the relocation is completed. Relocation projects are subject to the timing of the work triggering the relocation and as such timing of these projects is fixed.
- Reinforcements have fixed timing because absent the reinforcement, EGI would not be able to attach customers to its system after the reinforcement is required.
- Executing work has fixed timing as these projects have already commenced and therefore cannot be deferred.

Lowering the capital constraint would require EGI to reduce programs that directly maintain EGI's safe and reliable operations, for example:

- Compliance driven work, including integrity management work and meter exchanges.
- Program work with sufficient history and risk to warrant continuation, including AMP fitting replacements, inside regulator and ERR programs, distribution station replacement work, vehicle replacements and TIS infrastructure.
- Investments prioritized through EGI's Risk Management Process (**Section 4.2**).

- Copperleaf was used to optimize the 1,500 EGD RZ investments and 1,901 Union RZ investments in the initial pre-optimized ask. Using the optimization constraint values, the optimal capital timing was determined for proposed investments, as described in **Section 4.3.3**.
- The Decision with Reasons in the St. Laurent Ottawa North Replacement Project (EB 2020-0293) led to two subsequent changes to this AMP to ensure that there was adequate time to collect condition information and consider risk implications – St. Laurent Phases 3 and 4 (see **Appendix A, Pg. 13 &14**), and Wilson Avenue Vintage Steel Replacement (see **Appendix A, Pg. 10**). Investments in the 10-year plan that had sufficient timing for further, cost effective and prudent evaluation will continue to be assessed without prejudice to support the resultant investments. The LTC decision for St. Laurent is not expected to impact the Vintage Steel Replacement Program as this program and the associated selection of pipe replacements are based off of predictive analytics (condition and risk from the DIMP Risk Model as described in **Section 5.2.3.6.3.2**).

1.4.2 Optimization Results

Figure 1.4-1 presents the 10-year capital requirements by asset class with four years of historical spend for EGI. The final 10-year portfolio of spend was reviewed and approved by the Vice President of Engineering and the Asset Management Steering Committee.

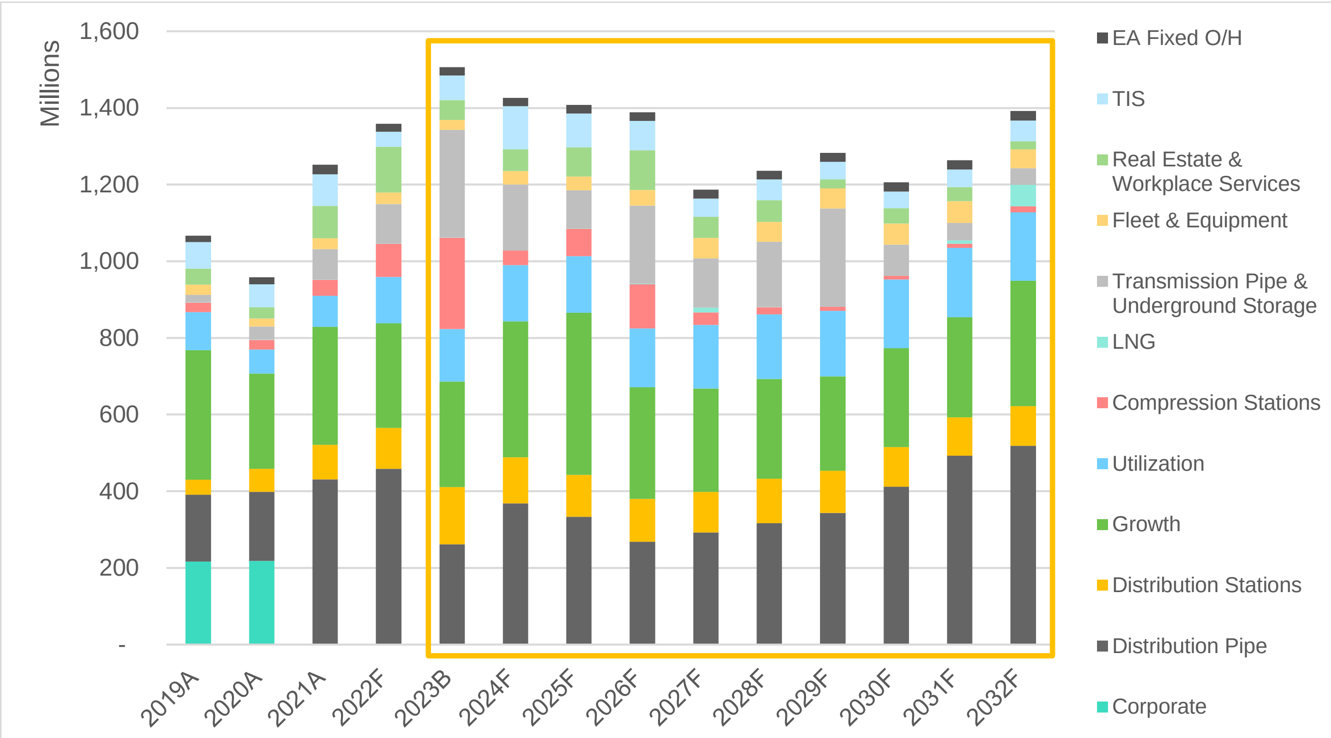

Figure 1.4-1: Final Ten Year Plan by Asset Class - EGI (Capital Expenditure)

Note: Historical actuals include both Capital Pass Through (CPT) Mechanism, ICM projects and integration capital. The total forecasted capital expenditure categorized by asset class depicted in **Figure 1.4-1** is comprised of each investment's direct costs and the associated overheads. Asset class historical spend profiles in 2019 and 2020 do not include associated overheads; for this reason, overheads are identified as a separate category historically. Due to the timing of the 2022 Forecast data, the 2023 Budget and 2024 Forecast include investments that have shifted out of 2022 that are also captured in the 2022 Forecast, for example St. Laurent Ph 3/4.

1.5 Assumptions

The 10-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 1.5-1: Assumptions for All Categories

Assumption	Basis for Assumption
Optimization results are based on available information as of March 2022.*	Based on EGI's Optimize Portfolio of Solutions process, the portfolio of spend is determined through the completion of Copperleaf leveling and subsequent reviews. Results are based on best available information. *The timing of St. Laurent Ph 3/4 and Wilson Avenue Vintage Steel Replacement project (see Appendix A, Pg. 10, 13 and 14) was updated in May 2022 following LTC Decision (EB-2020-0293).

Assumption	Basis for Assumption
Future costs are valued at 2022 Present Value.	Current practice forecasts projects based on 2022 rates.
Future costs do not include inflationary measures.	Normal inflationary measures and impacts such as rising material costs, foreign exchange and labour are expected to be covered within investment contingency. Incremental shifts in inflation caused by global supply chain shortages, pandemics or other unusual circumstances have not been considered. A small number of programs with defined scope/unit rates have included a factor where information was available to inform the assumption (such as meter purchases and vehicle purchases).
All cost estimates are based on available information as of March 2022.	Using EGI's AIPM process, these requirements will be reviewed and revised as required.
All Risk Assessments are based on risk models and methodology as of March 2022.	Using EGI's Risk Management process, EGI's significant operational risks are reviewed quarterly 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.
The proposed capital expenditures represent facility alternatives.	As this is the first year that EGI has applied the IRP Framework to the AMP, EGI's IRP assessment process (see **Section 4.3.4.1**). This IRP assessment process took place concurrent to the identification of the facility-based investments that underpin the AMP's 2023-2032 Capital Expenditures. Future iterations of the AMP will have proposed capital requirements that incorporate the comparison of viable facility and IRP alternatives to the extent possible prior to the next iteration of the AMP.

Table 1.5-2: 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. Renewal projects are planned to reduce this risk to the lowest practicable level.

Table 1.5-3: Customer Growth Assumptions

Assumption	Basis for Assumption
Customer growth is forecast using historical trends, and economic projections for the planning period.	The customer growth forecast considers projected housing starts, municipal growth forecasts, general economic indicators and projections, localized trends and macro-economic factors. EGI is cognizant that there may be impacts to customer growth forecasts based on climate/carbon policies.
Load forecasting is based on current understanding of temperature inputs described in Exhibit 3, Tab 2, Schedule 3 and estimated customer consumptions.	EGI has proposed a harmonized forecast methodology as part of this rebasing application. The estimated customer consumptions have historical Demand Side Management (DSM) built into the load forecast based on past results.

Table 1.5-4: Solution Planning Assumptions

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

2 Introduction

2.1 Purpose of the Asset Management Plan

On January 1, 2019, Enbridge Gas Distribution (EGD) and Union Gas Limited (Union) 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 3.8 million residential, commercial and industrial connections in Ontario, serving over 313 municipalities and 23 First Nation communities. EGI's 180 billion cubic feet (approximately five billion cubic metres) of regulated 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 assets is important for the secure, safe and reliable delivery of energy 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
- How Enbridge strategies and stakeholder commitments are linked to asset class strategies
- The integration of IRP and provide EGI's IRP Binary Screening and associated IRPA evaluation statuses by project (**Appendix B - IRP**)
- Process and governance for asset management planning including linkages to EGI's processes for managing risk
- Asset class objectives and life cycle management strategies
- Asset inventory, condition methodology, condition findings, risks, opportunities and renewal strategies
- Optimized 10-year capital plan required to manage assets from 2023 to 2032

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 expectations of the Ontario Energy Board (OEB) as set out in the *Handbook for Utility Rate Applications, October 13, 2016* and the *Filing Requirements for Natural Gas Rate Applications, February 16, 2017* and EB-2020-0091 Enbridge Gas Inc. *Integrated Resource Planning Proposal, July 22, 2021.*

2.2 Company Purpose, Vision, Values and Strategic Priorities

2.2.1 Purpose, Vision and Values

Asset management supports Enbridge's Purpose, Vision and Values (see **Figure 2.2-1**) by improving the Company's ability to operate safely and reliably, ultimately maintaining the satisfaction of 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 EGI is aligned with Enbridge strategic priorities.

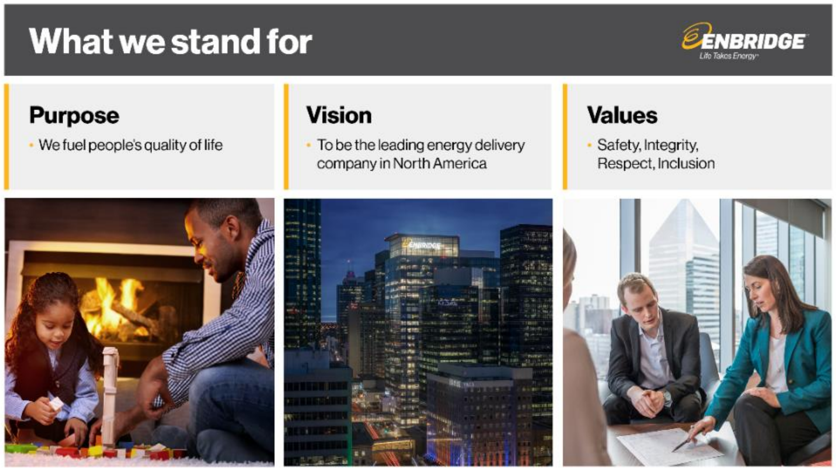

Figure 2.2-1: Enbridge Purpose, Vision and Values

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.

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, Inclusion.*

Enbridge continues to build on its foundation of operating excellence by adhering to a strong set of core values–*Safety, Integrity*, *Respect and Inclusion*–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.

2.2.2 Strategic Priorities

Enbridge's 2022 Enterprise Strategic Priorities (see **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, supporting the energy transition and positioning the company for future growth.

Figure 2.2-2: Enbridge Enterprise Strategic Priorities

2.3 Organization and Structure

Enbridge carries out its activities through four core business units: Liquids Pipelines; Gas Transmission and Midstream; Power, Business Development & Operations; and Gas Distribution & Storage (GDS) (see **Figure 2.3-1**). The GDS business includes EGI and other affiliate companies.

In addition, Enbridge's Central Functions teams (i.e., Finance, Corporate Development, Legal Services, Corporate Services, and Projects) enable business units to achieve their strategic goals.

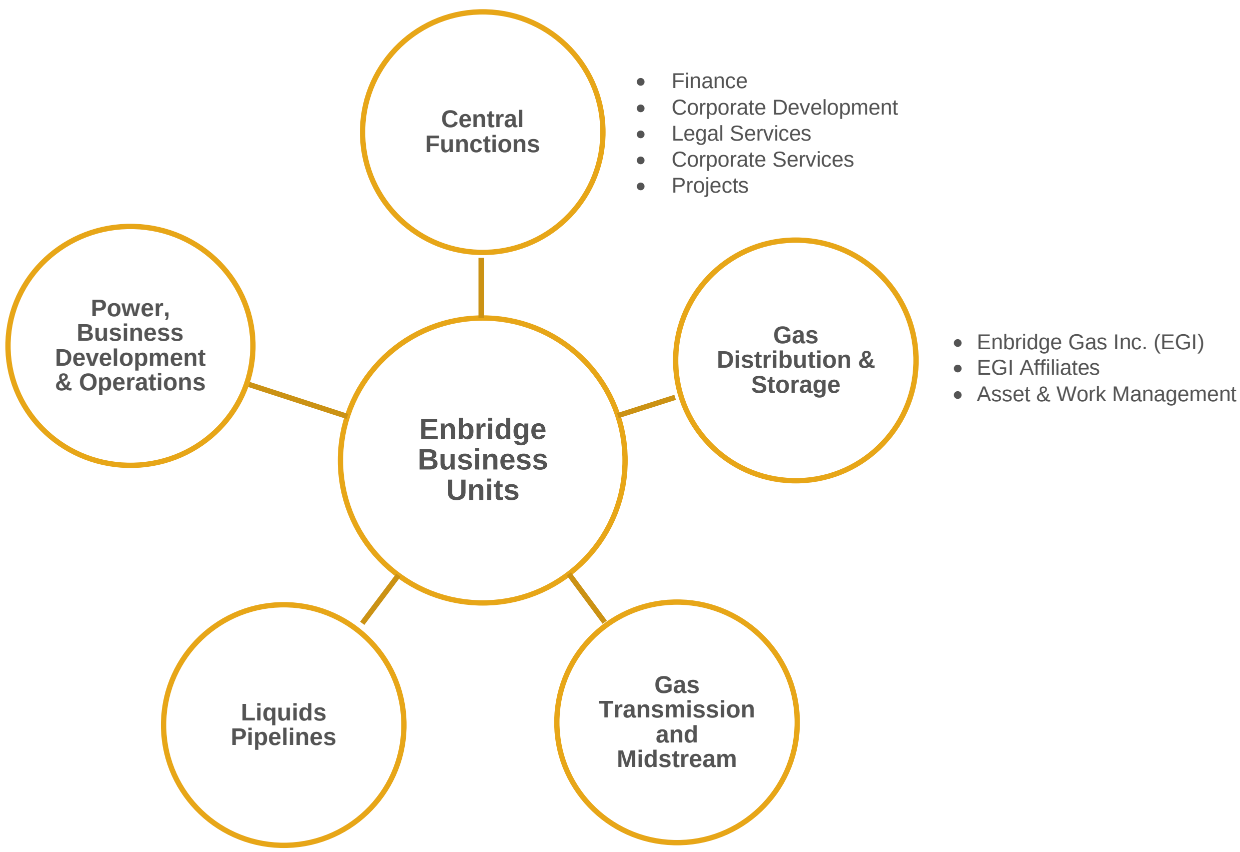

Figure 2.3-1: Enbridge Business Units

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.

2.3.1 Enbridge Gas Inc.

EGI serves over 3.8 million residential, commercial, and industrial customers in Ontario delivering 30% of Ontario's energy needs and heating 75% of homes in the province. EGI's distribution system supplies gas to commercial, agricultural, industrial and power generation applications that contribute to the economic health of Ontario. EGI is North America's third largest gas utility by customer count. EGI's franchise area is divided into seven operating regions as shown in **Figure 2.3-2**:

- Northern Region covers the legacy Union Northwest and Northeast districts.
- Southwest Region covers the legacy Union Windsor/Chatham and Sarnia/London districts.
- Greater Toronto Area (GTA) West and Halton covers the Western Greater Toronto (legacy EGD Area 20, 50) and legacy Union Halton districts.
- Toronto Region covers the city of Toronto (legacy EGD Area 10).
- GTA East Region covers the eastern Greater Toronto Area (legacy EGD Areas 30 and 40).
- Eastern Region covers legacy EGD Area 60, 90 (Gazifère[2]) and the legacy Union Eastern district.
- Southeast Region covers legacy Union Waterloo/Brantford and Hamilton districts, and Niagara (legacy EGD Area 80).

EGI has storage and transmission assets which 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 gas supplies in the Western Canadian Sedimentary Basin and the Utica and Marcellus producing regions in the U.S. It is similarly connected to the major demand markets in those areas, 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.

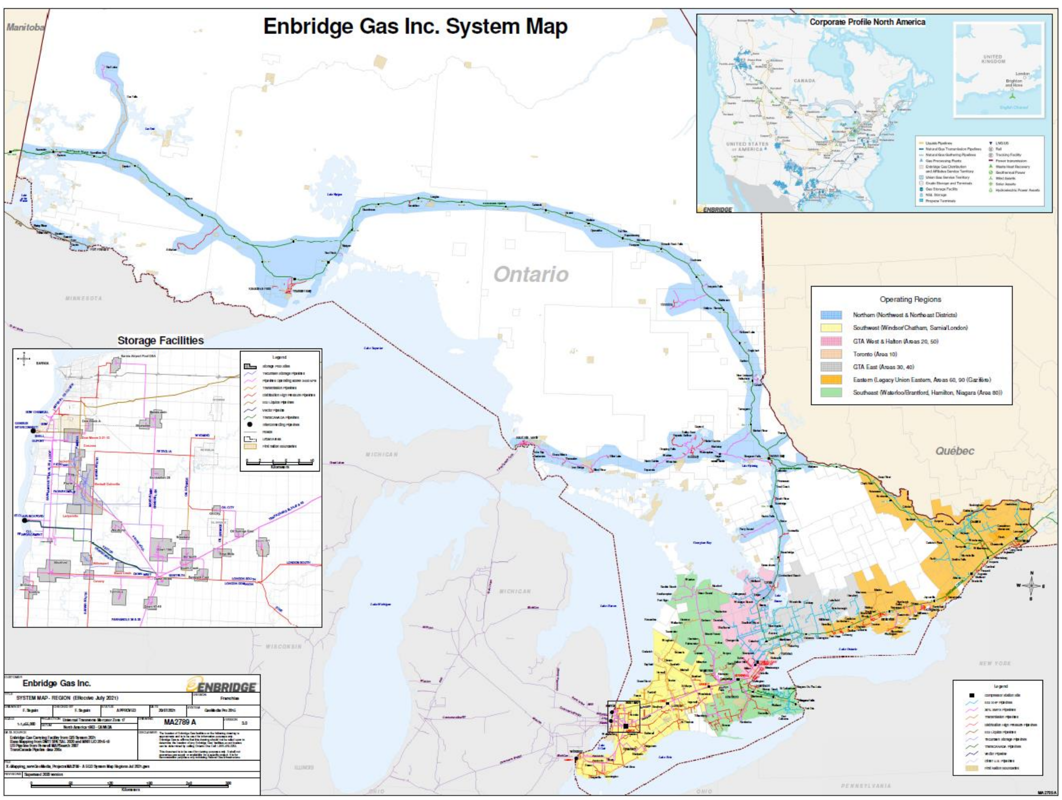

Figure 2.3-2: EGI Operating Regions

[2] Gazifère assets are not in scope of this Asset Management Plan.

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, and 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. See Exhibit 1, Tab 10, Schedule 5, Section 2 for detail on how stakeholder commitment is incorporated into energy transition.

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' needs and preferences and to incorporate the findings into their Utility System Plan (USP). EGI's Asset Management Plan is a component of the USP (refer to Exhibit 2, Tab 6, Schedule 1).

To this end, EGI conducted an extensive customer engagement process throughout 2021 and early 2022 (refer to Exhibit 1, Tab 6, Schedule 1).

Further to the results described in the **Overall Results** of Exhibit 1, Tab 6, Schedule 1, additional results referenced in this AMP are summarized here:

- **The majority of residential customers agree that EGI should actively invest in low-carbon solutions** including energy efficiency technologies, hydrogen gas, renewable natural gas and carbon capture, utilization and sequestration (CCUS). These solutions would help reduce impacts on the environment and that EGI is well positioned to support the development of low-carbon options and solutions.
- **Compression Stations:** The majority of residential customers and business customers would prefer to replace aging compressor stations to minimize the risk of failure, knowing that the compressor replacements would translate into an increase in their natural gas bill during the 2024 to 2028 period.
- **Vintage Steel Replacement Program:** Over half of residential customers and business customers prefer to increase spending on the Vintage Steel Replacement Program in order to help prepare the system for the future by proactively ramping up spend, which would increase their bills.
- **Hydrogen Gas:** Over half of customers prefer that EGI implements plans to increase the use of clean hydrogen as a tool for reducing GHG emissions in Ontario, which would increase their bills.
- **Advanced Meter Infrastructure:** The majority of customers support the installation of Advanced Meter Infrastructure in order to achieve the enhanced benefits outlined in Exhibit 2, Tab 7, Schedule 2.

These results demonstrate that customers are aligned with EGI's commitment to the safe, reliable, cost-effective and environmentally responsible provision of energy. 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:

- Asset management goals include employee and public safety, compliance, financial performance, value-based decision-making that incorporates environmental sustainability and the transition of customers' needs to low-carbon energy solutions 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.

2.4.2 Indigenous Consultation and Engagement

EGI is committed to building respectful and foundational relationships with Indigenous groups. In Ontario, the Community and Indigenous Engagement (CIE) team supports all utility engagement, and regularly interfaces with approximately 50 Indigenous communities both currently being served by natural gas and prospective service communities, and communities in proximity to EGI operations. EGI's life-cycle approach to engagement includes standards of practice for formal consultation on proposed projects, but also engagement for building respectful, constructive and enduring relationships that foster trust with and generate benefits for Indigenous groups over the life-cycle of EGI assets.

For new asset initiatives, EGI aims to enhance its existing relationships built through ongoing engagement and open a dialogue that will inform decision-making from the project proposals and design phase through to construction, operations, and maintenance to safely remove a pipeline from service at the end of its useful life. EGI engages in forthright and sincere consultation and engagement with Indigenous Peoples about EGI's projects and operations through processes that seek to achieve early and meaningful engagement so communities' input can help define projects and plans that may traverse Treaty lands and traditional territories of Indigenous Nations.

3 Asset Management Strategic Framework

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

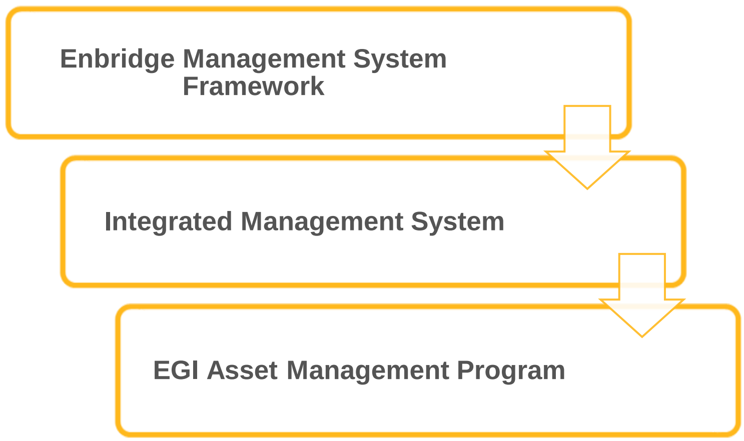

Figure 3.0-1: Alignment of Standards and Requirements

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 several 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 Enbridge 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 (see **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.

PDCA 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

3.1 Asset Management Framework

The IAM Conceptual Asset Management Model (see **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. The IAM model guides EGI in the development of an asset management framework aligned to *ISO 5500X* and demonstrates the 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.

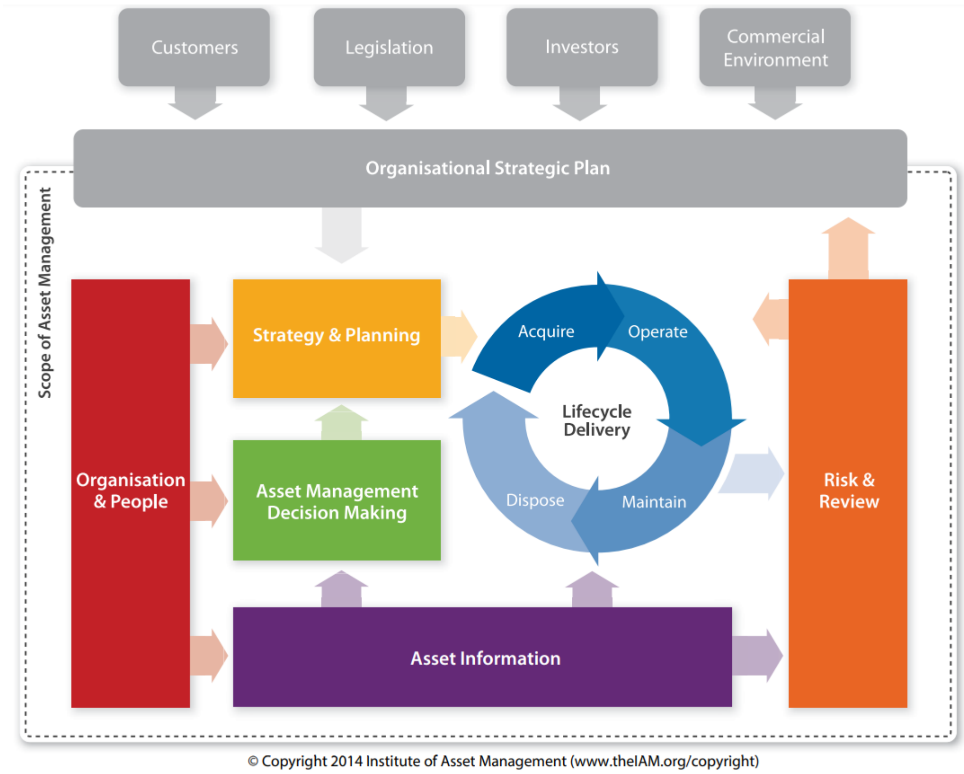

Figure 3.1-1: IAM Conceptual Asset Management Model

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 6 subject groups in alignment with the 6 major asset management components:

Strategy and Planning: The adoption and maintenance of a governance framework used to align Asset Management Plans and decision-making within the Enbridge's overall strategic objectives.

Organization and People: The development and maintenance of 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.

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

Risk and Review: The identification, assessment, evaluation, treatment and monitoring of risks, resulting in prudent resource allocation and balancing risk, cost and performance.

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, opportunity, cost and performance in making asset investment decisions over the whole life cycle of the asset.

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

3.1.1 Enbridge Strategic Priorities

The Enbridge Strategic Priorities (see **Section 2.2.2**) enable the Company 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 energy 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 as EGI supports the transition to a low-carbon future. Optimal value will be delivered to customers and stakeholders through a sustainable investment plan that balances cost, risk 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 and low-carbon energies 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

Asset Management goals include employee and public safety, compliance, value to stakeholders and financial performance. EGI's value-based decision-making incorporates environmental sustainability, and the transition of customers' needs to low-carbon energy solutions. EGI employees must consider these goals when evaluating costs, risks, and performance related to asset investment decisions over the whole asset life cycle. Decisions are made through documented and transparent evaluation processes including recent additions related to the IRP Framework (EB-2020-0091).

EGI leverages an Asset Management Program based on the industry standard, Global Forum on Maintenance & Asset Management (GFMAM), to demonstrate a systematic and coordinated approach to asset management activities. Consistent practices, processes and tools are used to manage assets optimally and sustainably. This is be achieved by balancing cost, risk, and performance throughout the asset's life cycle while providing value to customers and stakeholders.

Policy Statements

1. EGI continuously improves and aligns 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 that incorporates energy transition for all asset-related investments on a holistic evaluation of cost, risk, and performance.
3. EGI is committed to sustainable/lower-carbon initiatives, including IRP, and new energy solutions, as well as the incorporation of these strategies within Asset Management planning and investment decisions.
4. EGI is committed to a 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 energy.
5. EGI acknowledges that asset information is critical to transparent knowledge-based decision-making. EGI ensures that its processes, systems and controls collectively strive to deliver verifiable, traceable, complete, timely, accurate and accessible asset information.
6. EGI is committed to meeting or exceeding compliance with all applicable laws and regulations, industry codes, standards and internal policies.
7. EGI is committed to understanding and delivering value to its customers and stakeholders.
8. EGI uses this policy and EGI's Asset Management Program to guide asset investments, as endorsed by Senior

Leadership, over the life cycle of each asset class.

3.2 EGI Integration and Continual Improvement

This document reflects the integrated utility's Asset Management Plan for the next 10 years, with assets for the rate zones (the EGD and the Union North and South rate zones) being maintained separately for capital planning purposes in 2023 and as EGI from 2024 through to the end of 2032.

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

- **Energy Transition**
  This AMP incorporates assumptions for customer additions, peak hour demand and peak day demand, each of which have been adjusted to reflect EGI's current view of the impacts of the Energy Transition (see Exhibit 1, Tab 10, Schedule 4). EGI acknowledges that energy transition is evolving and that investment decisions will be based on the best information at the time, including consideration of IESO's forecast electricity demand. EGI maintains its obligation to serve and is committed to implementing IRP with the intent of evaluating and comparing both supply-side and demand-side options to meet an energy system need in the immediate, medium and longer term.

- **Integrated Resource Planning (IRP)**

  IRP represents a significant change to the facility planning that EGI has performed in the past and, as such, EGI is taking steps to develop processes, resources and capabilities to integrate new IRP requirements into its existing asset management process and other processes. EGI's AIPM process now incorporates the IRP assessment process. The IRP assessment step of the AIPM process (see **Section 4.3.4.1**), determines if an IRPA evaluation is required for each system need, and, if so, a cost-effective IRPA exists. Further details on the IRP assessment process can be found in EGI's IRP Annual Report.

  Through the IRP assessment process, EGI has performed IRP Binary Screenings on eligible projects, consistent with the guidance provided by the OEB in its Decision. The IRP Binary Screening results and the associated IRPA evaluation statuses, by project, can be found in **Appendix B – IRP**.

- **Alignment with Enbridge Inc.'s 2022 Enbridge Strategic Priorities**

  Enbridge Inc. published a revised Strategic Plan in 2022. 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**.

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

  The phase two Boundary and Real Estate initiative has been completed. EGI's regional boundaries and real estate assets across the province were reviewed to align current boundaries and strategically locate EGI's operating depots. The second phase of the initiative evaluated the area between the GTA West and Southeast regions. In January 2022, the regional borders were realigned to optimize the facilities within each new region.

- **Consolidation of asset data**

  The systems of record for asset data in the Union rate zones include Maximo for meter, work, damage and condition data; SAP-PM for station work and asset data; GIS for pipe data; and CORR for corrosion data. Some data that supports the Asset Management Plan is now being migrated to a datamart as part of the integration of work and asset management systems. Ongoing documentation and consolidation of these datasets will enable EGI to analyze inventories more efficiently for the combined utility and better support the Integrity and Asset Management functions.

- **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
  - Mapping the capital expenditures presented in **Section 5** to the asset class strategy
  - Identification of outstanding items that remain in legacy programs until they can be integrated

- **Integration items to highlight**

  Standards for installation, inspection, operation, maintenance, and asset decommissioning continue to be integrated. This work is ongoing; some legacy practices continue to be followed for each rate zone as analysis deemed it as appropriate for the assets at this time. Other design changes may be implemented on a go-forward basis. These new standards are reflected in this Asset Management Plan and will continue to evolve throughout the integration process. Specific integration efforts include:

- **Integrity Management Program**

  EGI continues to evolve its Integrity Management Program based upon industry best practices and incident learnings. EGI has developed a quantitative risk model to assess the primary risk for pipeline assets within the distribution system which is being leveraged to identify and prioritize assets that are approaching end of life and need to be replaced. Transmission pipeline assets already have a quantitative risk model; however, that model has also been enhanced with additional hazards and consequences, as well as the development of Safety Targets to further assess the risk of Transmission Integrity Management Program (TIMP) assets.

  Detailed documented assessments (i.e., Integrity Plans) for assets or assets groups are being created to ensure the following:

    - All potential hazards are considered.
    - Appropriate inspection methods and timing are determined.
    - Inspections are completed.
    - Results are assessed.
    - Any required repairs are made.
    - The fitness for continued service is confirmed.

  EGI has introduced the use of Safety Cases as an independent check that all hazards have been effectively considered and addressed. Safety Cases will initially be developed for a subset of the TIMP assets and expanded to other assets over time.

- **Fleet and Equipment**

  EGI continues to standardize processes and procedures related to the assignment of vehicles for the appropriate roles, types of vehicles required to support employees in performing their roles, and vehicle maintenance and repair model.

- **Technology and Information Services**

  TIS continues to support process and system integration while in parallel reducing EGI operational and cybersecurity risks. EGI continues to align systems, processes and procedures, prioritized based on business value (efficiency, safety/reliability, security, compliance) while adopting industry best practices regarding cloud computing where feasible.

- **Modelling enhancements from Distribution Optimization Engineering**

  EGI has harmonized its approach to degree day forecasting and system modelling for growth; the resultant facility requirements form the basis for reinforcement forecast in this Asset Management Plan.

- **Operationalizing the Asset Plan**

  As EGI develops the maturity of its Asset Management practice, greater focus is placed on measuring delivered work relative to planned work, highlighting the need for multi-year planning and the identification of resources required to execute the plan, including the resources required to scope, plan and obtain required approvals. Accomplishments of this initiative include:

    - Documented and communicated Asset Investment Planning and Management (AIPM) processes, procedures, and accountabilities.
    - Improved communication and training to promote consistency.
    - Identification of incremental resources to support delivery of the asset investment plan.

- **10-Year Asset Management Plan**

  This version of EGI's AMP considers a ten-year horizon with the understanding that the scope of investments in the earlier years of the plan are more refined than those in later years. Considering a 10-year window allows time to consider and develop feasible IRPAs to meet the identified system needs.

- **Value Assessment Quality Assurance Approach**

  As the application of the Copperleaf value framework evolves, EGI has developed a continual improvement approach to validate and calibrate investment data, capture best practices, and to maximize value in the AMP. Emphasis was placed on applying data analytics practices and sense-checking investment data to better understand how EGI's value assessment processes are working and how they can be improved. Implementing this approach led to:

- Increased support for Asset Management optimization and calibration activities to ensure consistency and alignment of investment data.
- Greater stakeholder engagement and transparency of value across EGI's portfolio of opportunities.
- Identification and documentation of improvements to the Copperleaf value framework.

- **Greenhouse gas emission reductions**

  Enbridge continues to evaluate and implement facility emission reduction opportunities by ensuring initiatives effectively balance customer preferences, compliance obligations, anticipated future regulations and other benefits such as safety and operational reliability. In the evaluation of system expansion alternatives, the cost of fuel and carbon are considered along with operational requirements. These opportunities are tracked through the GHG Scope 1 & 2 Working Group. The GHG Scope 1 & 2 Working Group will identify and review potential opportunities and strategies to achieve cost-effective GHG reductions, which are incorporated into asset class life cycle strategies, as well as operating practices, equipment modernization and innovation, and emerging policies and regulations. EGI's efforts in reducing its environmental footprint are closely tied to the work outlined in this Asset Management Plan.

3.3 Energy Transition

All three levels of government (federal, provincial and municipal) as well as Indigenous groups are focused on addressing climate change by reducing GHG emissions through setting targets and implementing policies. At the same time, access to energy and energy affordability are key issues that must be addressed in Ontario and EGI remains obligated as the supplier of last resort to meet the peak design day demands of its existing customers safely and reliably.

EGI is committed to partnering with the province, as well as municipalities and Indigenous groups across the province, to achieve the various GHG emission reduction targets set out within their respective energy transition and sustainability plans. including increasing energy efficiency and reliance on renewable energy sources.

This Asset Management Plan outlines the needs and resultant investments of EGI's assets to ensure that EGI can safely and reliably meet the peak design day demands of new and existing customers and how EGI is beginning to transition assets to meet future energy needs. EGI has conservatively included some assumptions related to energy transition in the forecasts EGI uses for planning purposes. This AMP incorporates assumptions for customer additions (see **Section 5.1.4**), peak hour demand and peak day demand, each of which have been adjusted to reflect EGI's current view of the impacts of the Energy Transition. For more detail, refer to Exhibit 1, Tab 10, Schedule 4.

EGI acknowledges that energy transition is evolving and that investment decisions will be based on the best information at the time. As practical, verifiable and prudent alternatives are available and energy transition assumptions are understood, EGI will adjust and adapt its planning processes to continue to securely, safely and reliably serve customers giving due consideration to the evolving nature of the use of natural gas. EGI is anticipating developments in the following areas:

- Increased adoption of low-carbon technologies
- Implementation of economically and technically feasible IRPA's
- Refinement of energy transition assumptions as information is confirmed, impacting the following:
  - EGI's forecasting methodologies for customer connections and growth
  - Adjustments to asset life cycle considerations and strategies
  - Updates in timing and scope of reinforcement investments

EGI has engaged two external consultants, (1) Posterity Group and (2) Guidehouse, to analyze the impact of climate policies and energy transition. The Guidehouse study showed that a diversified pathway, one that continues to leverage the existing the gas infrastructure, is a more affordable, reliable and resilient pathway for Ontario. In a diversified pathway, the current gas system transitions over time to deliver low-carbon fuels, including hydrogen and RNG. A discussion of this work can be found in Exhibit 1, Tab 10, Schedule 5. In addition, based on the feedback EGI received in the 2024 Rate Rebasing Customer Engagement, the majority of customers agree that EGI should actively invest in low-carbon options and solutions that will help reduce environmental impacts.

EGI's Hydrogen Strategy is described in **Section 5.1.8**, which includes the expansion of EGI's existing Low Carbon Energy Project in Markham and evaluating the extent that hydrogen can be used in the distribution system and other company assets. These proposals will allow EGI to increase the amount of hydrogen the Company is delivering and inform the future state of Hydrogen as a low carbon energy source at EGI.

EGI's RNG Station Strategy is described in **Section 5.2.4.6.1.7**, where EGI is pursuing opportunities to inject this into the distribution system as RNG becomes more available.

In addition to hydrogen and RNG, EGI outlines the energy transition-related initiatives it is exploring and pursuing in Exhibit 1, Tab 10, Schedule 6.

3.3.1 Integrated Resource Planning (IRP)

In 2021, the OEB released its Decision and Order in the Enbridge Gas Inc., Integrated Resource Planning Proposal (EB-2020-0091) which indicated that EGI's AMP should include the status of consideration of IRP Plans in regard to meeting system needs, the result of binary screening and details on the evaluation. **Appendix B** has been included in the AMP to meet that commitment; **Sections 3.3.1** and **6.3** of this AMP provide a high-level background and context for this Appendix. The **Appendix B** tables provide the review status of each investment in the AMP that went through binary screening.

EGI has been focused on advancing IRP as directed in the OEB's IRP Decision (EB-2020-0091). At the time the Decision was issued, EGI staff were in the process of identifying system needs to support the 2023-2032 Asset Management Plan. These needs are traditionally addressed through facility alternatives which take several weeks and sometimes months to develop and evaluate, and to determine if they warrant capital investment. In parallel to this process, EGI developed an approach to screen and evaluate IRPAs in alignment with the high-level IRP process laid out by the OEB in its Decision. In the development and initial implementation of this approach, EGI has directed a significant effort towards the following activities:

1) **Review of Identified Investments in the 2023-2032 Capital Plan and Binary Screening**: The 2023-2032 capital plan was finalized in June 2022. Although the 2023-2032 capital plan contains investments that were also in the 2021-2025 AMP, Enbridge Gas felt it was most prudent to finalize the 2023-2032 capital plan prior to the initiation of its IRP assessments, as investment scope, cost and timing were expected to change within the first harmonized, combined, utility asset management plan. The review of projects and application of the IRP binary screening criteria was then completed for all 3087 projects within the 2023-2032 capital plan.

2) **IRP Pilot Project Selection**: The IRP Decision (EB-2020-0091) indicated that two IRP pilots should be selected and implemented by December of 2022. This IRP Pilot assessment and selection process was resource and time intensive, as it involved several steps and discussions, including meetings with the IRP Technical Working Group (TWG) for feedback. Efforts were focused on the following aspects.
   a. Definition of the pilot objectives, key considerations, and criteria for selection, such as system configuration, customer mix and potential for peak hourly flow data collection.
   b. Review of projects in the 2023-2032 capital plan and short-listing projects and associated systems as potential pilot options; factoring in the objectives and pilot section criteria.
   c. Detailed review of potential pilot project options including the identified system needs (multiple for the portfolio pilot), system growth and peak hour demand reductions required.
   d. High-level IRPA feasibility evaluation; this included reviewing supply-side bridging solutions and understanding the system and market characteristics to help gauge the potential of implementing a geo-targeted solution.

3) **Technical Evaluation:** A technical evaluation is the first step of the IRP two stage evaluation process. Investments in the 2023-2032 capital plan cover a wide range of assets, that are managed by numerous teams throughout EGI. The IRP team engaged investment owners, SMEs and Asset Managers to together determine how IRP principles would apply to their projects. The IRP team is now working with the same group of investment owners, SMEs and Asset Managers to complete a detailed review of the projects, as outlined in **Section 6.3.4 Technical Evaluation Project Review**.

4) **Economic Evaluation:** An economic evaluation is the second step of the IRP two stage evaluation process. This step relies on the DCF+ Test. As directed in the IRP Decision, the IRP team is engaged in enhancing the DCF+ economic evaluation test that will be utilized to determine the optimal IRP or facility solution. To date, this work has involved engaging a consultant to assess how the DCF+ test could be evolved, jurisdictional scans to better understand how other utilities have assessed non-pipeline alternative investments and whether those learnings are applicable to EGI. Additionally, an IRP TWG subgroup has been formed to discuss considerations and issues brought forward by members of the TWG for the enhanced DCF+ test.

5) **IRP TWG Meetings** were previously held monthly, now biweekly. The IRP team has dedicated time and resources to prepare materials for these meetings. Various teams are engaged to contribute content, as well as, addressing the takeaway items from the previous meeting.

Appendix B reflects the current state of EGI's IRP Assessment process, as described in **Section 4.3.4.1** of the AMP. **Section 6.3** provides details on the methodologies and process, and the **Appendix B** tables that follow provide the evaluation at the investment level, at the time of filing. EGI will continue to assess investments in the 10-year capital plan for IRPA feasibility. As this is the first year that EGI has applied the IRP Framework to the AMP, a detailed and time-intensive review of all facility-based investments has been required, which includes an in-depth evaluation of the projects to understand the project need, drivers, system grouping opportunities and potential for IRP alternatives. The IRP Assessment Process will become less time intensive as it is further integrated into the Solution Planning & Value Assessment stage of the AIPM process, and as it becomes focused on new investments or those that have changed since the last iteration of the AMP.

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.

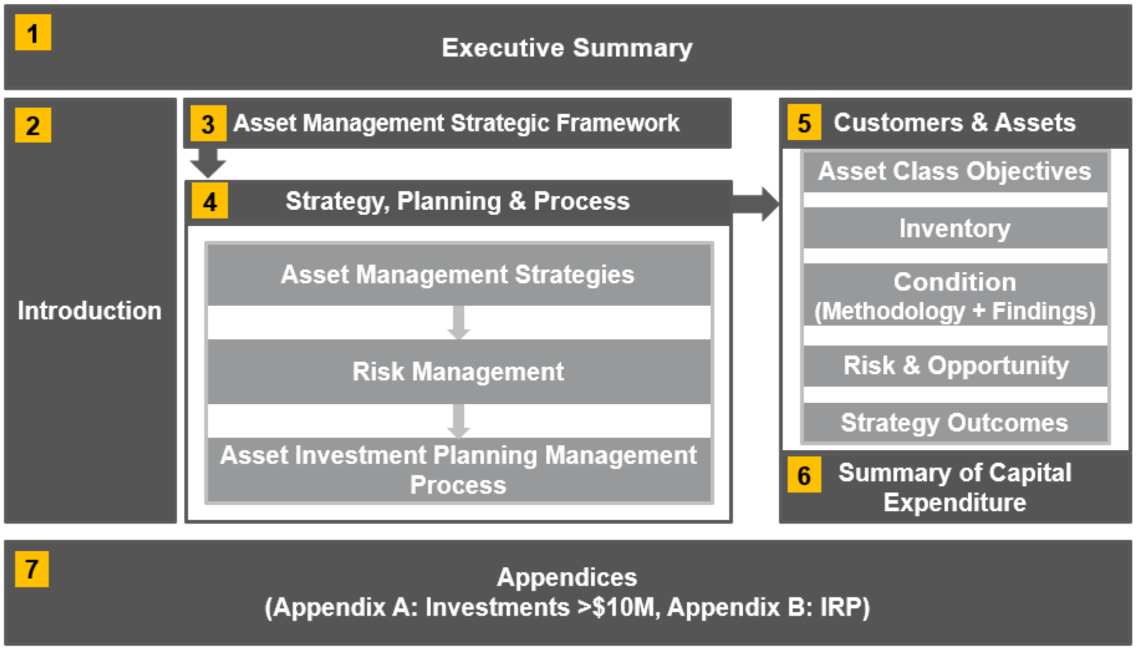

Figure 3.4-1: EGI's Asset Management Plan Structure

Executive Summary (Section 1): This section provides a summary of the Asset Management Plan.

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, Energy Transition, IRP, and the structure of the document.

Strategy, Planning and Process (Section 4): This section details the alignment of asset management at EGI with the Enbridge strategic priorities and includes EGI's asset management strategies, risk management and the Asset Investment Planning and Management (AIPM) process.

Customers and Assets (Section 5): This section details the following:

- EGI's customers and the customer growth projections
- Asset class objectives
- Asset class strategies
- 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 10-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 10-year portfolio of spend.

Appendices (Section 7): The appendices present supporting information for the Asset Management Plan. Appendix A includes descriptions of discrete investments with a Net Base Capex greater than $10M in 2023 to 2032. Appendix B – IRP contains the IRP Binary Screening and associated IRPA evaluation statuses by project.

4 Strategy, Planning and Process

EGI's Asset Management framework is aligned to Enbridge's Strategic Priorities, the EGI Asset Management Policy and Asset Management Strategies (see **Section 4.1**). This alignment provides a foundation that supports the Asset Investment Planning and Management (AIPM) process (see **Section 4.3**).

Figure 4.0-1: Asset Management Alignment

- **Enbridge Strategic Priorities (Section 2.2.2)** sets the foundation for all company-wide operations and initiatives.
- **Asset Management Policy (Section 3.1.2)** translates the Enbridge 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)** supports the policy and outlines the methods employed for asset management success.
- **Risk Management Process (Section 4.2)** involves a series of activities designed to help management assess, prioritize, and treat hazards and risks that could affect the achievement of key business objectives.
- **Asset Investment Planning and Management (AIPM) Process (Section 4.3)** outlines how the identified strategies will be executed.

4.1 Asset Management Strategies

The EGI Asset Management Program's day-to-day activities are driven by key asset management strategies (see **Figure 4.1-1)** aligned to the six framework components of the IAM Conceptual Asset Management Model (see **Figure 3.1-1**) and operationalized through the Asset Investment Planning and Management (AIPM) process (see **Section 4.3**):

Strategy and Planning

- 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.

Organization and People

- 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.

Life Cycle Delivery

- 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

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

Asset Management Decision-making

- Optimize portfolio based on asset management principles.
- Improve decision-making through transparency, clear accountabilities, stakeholder engagement and use of common asset management tool.
- Extend asset management decision-making to 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 risk, value assessment and timing considerations for outages.

Asset Information

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

Figure 4.1-1: Asset Management Strategies

4.1.1 Strategy and Planning

EGI uses a governance framework to align asset management plans and decision-making within the Enbridge's overall strategic objectives. The strategies to achieve this are:

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

The alignment of EGI's Asset Management Program with organizational priorities (see **Figure 4.1-2**) 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 (10-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 (see **Section 6**).

4.1.1.1 Alignment of Enbridge Strategic Priorities and Asset Management Strategies

Figure 4.1-2 illustrates how EGI's Asset Management Policy, strategies and value measures align with Enbridge's strategic priorities. This alignment is the core of EGI's Asset Management Strategic Framework.

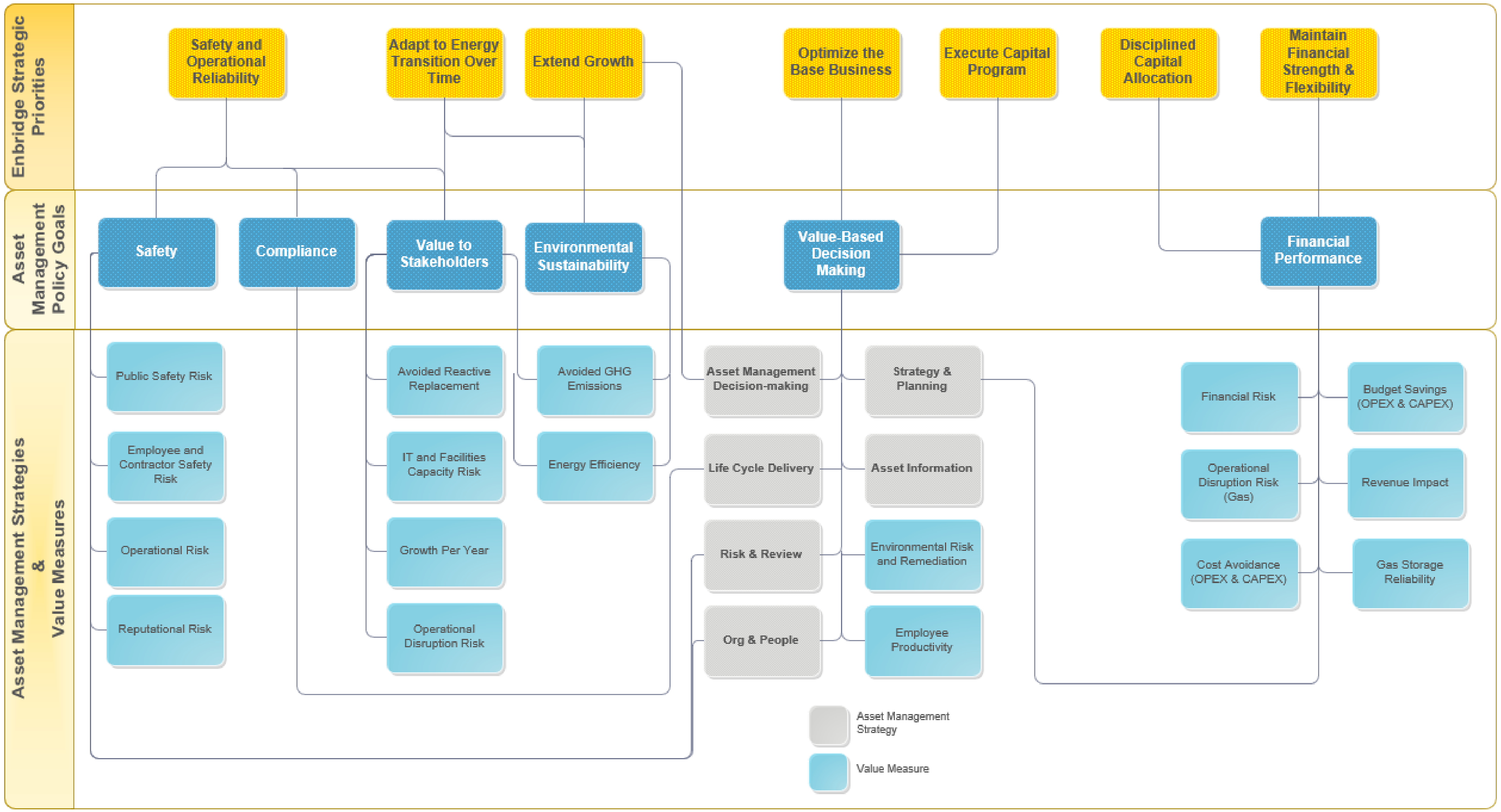

Figure 4.1-2: EGI's Alignment of Enbridge Strategic Priorities and Asset Management Strategies

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4.1.2 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 and objectives.
- Establish a leadership/culture framework to embed asset management awareness and principles throughout the organization.

Asset classes at EGI (see **Figure 4.1-3**) 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 for their asset class and for managing the portfolio of work to ensure risk is managed to the lowest practicable level and optimum value is realized.

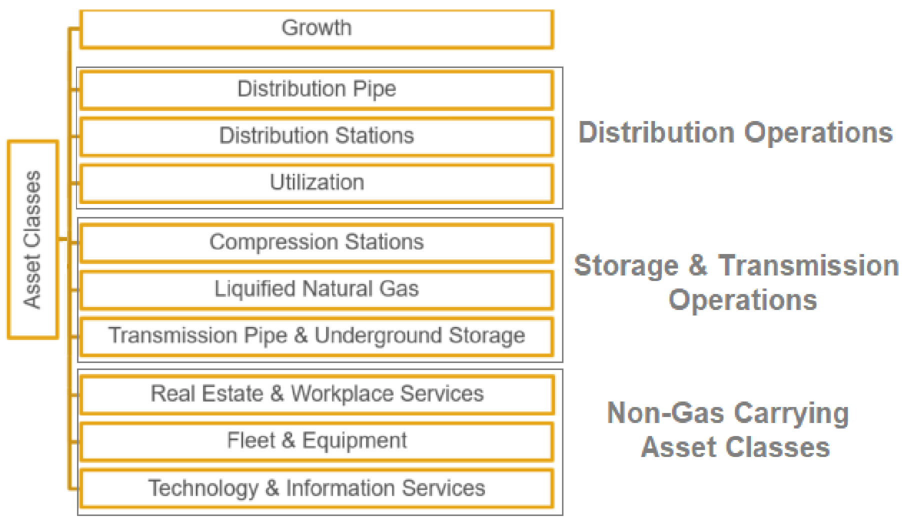


Figure 4.1-3: EGI Asset Classes

A matrix approach to asset management (see **Figure 4.1-4**) 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 (IMS) and the Safety and Reliability Governance Team. Key functions in this matrix approach work together to achieve an optimized portfolio:

- The **Asset Management Director** performs the following:
  - Demonstrates commitment to values and principles of Asset Management set out in the Asset Management Policy, Objectives and Strategic Asset Management Plan
  - Promotes continual improvement
  - Decides on the set of investments that will address risk across EGI through the recommendation of the capital portfolio
  - Ensures resources for the Asset Management Plan are available and actively directs and supports people to contribute to effective asset management
  - Supports and influences staff to deliver the Asset Management Strategy and objectives of the organization
  - Endorses Asset Management Plan documentation
- **Asset Management and Risk 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
- Risk Management Framework, Standards, Processes and Value Framework
- Asset Investment Planning & 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, opportunities, and emerging needs
  - Preparation of investments for value assessment
  - Proposal of potential solutions to identified needs
  - Prioritization of solutions and risk treatments across the asset class
  - Development of strategic plans for the asset class which incorporates IRP
  - Stakeholder review and management

- **Functional/Process Departments** support asset management by providing:
  - Integrated Resource Planning Alternative assessments
  - Engineering assessments
  - Value assessments
  - Integrity assessments
  - Energy transition design and analysis
  - Risk owner, accountable for ensuring that a risk is managed throughout the Risk Management Lifecycle (see **Section 4.2**)
  - Asset analytics
  - Records management
  - Financial support
  - Regulatory support including energy policy
  - 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 Investment Planning and Management process described in **Section 4.3** to ensure that capital expenditures are based on transparent and defendable asset-based decisions.

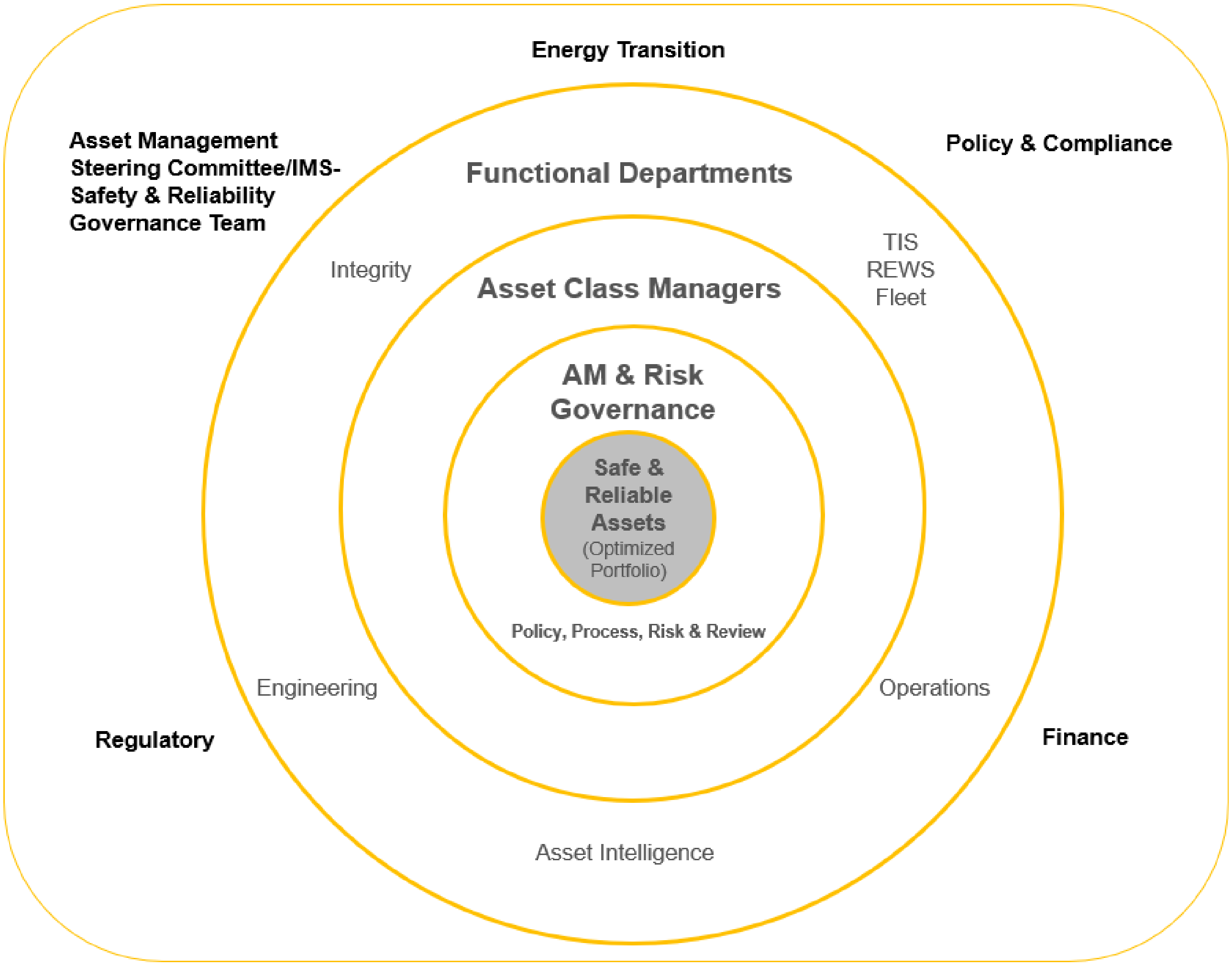


Figure 4.1-4: A Matrix Approach to Asset Management

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 drive the 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 (see **Figure 4.1-5**), adapted from the IAM Conceptual Asset Management Model (see **Figure 3.1-1**):

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

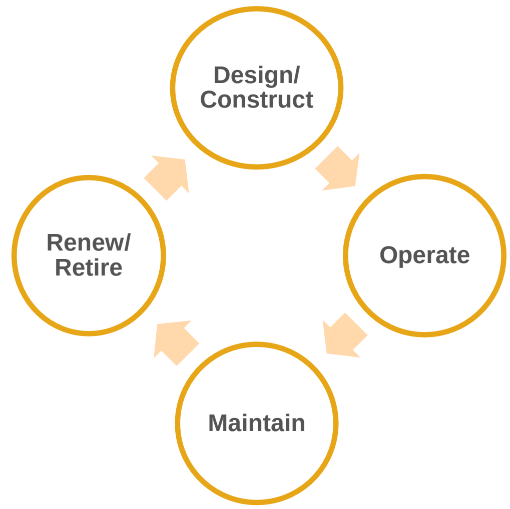


Figure 4.1-5 Asset Life Cycle Stages

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

Table 4.1-1: Life-Cycle Management for Assets

Life-Cycle Stage	Activities
Design/Construct	• Design new assets to: • Ensure the safe and reliable delivery of natural gas. • Ensure worker and public safety. • Ensure code compliance. • Support energy transition. • Meet current and future demand requirements. • Reduce risk to the lowest practicable level. • Ensure critical components and systems have multiple layers of failure protection. • Ensure components and systems can be made safe in a reasonable period. • Minimize environmental impact and GHG emissions. • Minimize future maintenance needs. • 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: • Ensure the safe and reliable delivery of natural gas. • Ensure worker and public safety. • Meet or exceed compliance standards and procedures. • Meet current demand. • Minimize end-user disruption.

Life-Cycle Stage	Activities
	• Use assets in the most cost-effective manner. • 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.
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 overpressure 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 employee and contractor health and safety, support energy transition, 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 regulatory codes and standards.

4.1.4 Risk and Review

EGI aims to manage risks through the adoption of a Risk Management process (see **Section 4.2**) based on ISO 31000 and the Enbridge Framework Standard on Risk Management. The strategies to achieve this are to:

- Establish a framework to identify, analyze, evaluate, and treat risk.
- Implement processes based on the framework to management risks.
- Monitor asset performance, health and risk to balance risk, cost and performance.

Asset performance, health and risk is monitored through a range of formal and informal methods including condition assessment programs, tracking of performance data through Management Programs (part of the Integrated Management System), the Asset Health Review and the Hazard Identification and Risk Assessment process.

Through these inputs and the Risk Management process, EGI manage risks in the following categories:

- **Employee and Contractor Health and Safety**: Level of injury or illness and number of employees impacted
- **Public Health and Safety**: Level of injury or illness and number of people in general public 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 and 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

4.1.5 Asset Management Decision-Making

EGI aims to have a clear framework for asset investment decision-making that 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, 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.

Investments fall into one of three categories based on asset management principles: mandatory, compliance or value-driven, as described in **Table 4.1-2**. These categories support portfolio optimization and the determination of optimal investment timing through the AIPM process **Section 4.3**.

Table 4.1-2: Investment Categories

Investment Category	EGI Description
Mandatory	An investment that is required to address a risk or opportunity within its required time window. Mandatory investments can be the result of: • Exceeding an established risk upper threshold • Third-party relocation • Program work with sufficient history and risk to warrant continuation • Projects that meet the economic feasibility tests in *EBO 188* and *EBO 134*
Compliance	Investments required to adhere with applicable laws and regulations, industry codes, standards and internal policies. Compliance investments receive the same treatment as mandatory investments–both must be addressed within their required time frame.
Value-Driven	Investments whose timing is determined based on consideration of the value it brings to the ratepayer and the organization. Value and investment timing can be informed via the **Copperleaf value framework** or via the GDS Risk Management process (see **Section 4.2**).

EGI uses Copperleaf, an asset investment planning tool that provides a common economic scale, to understand and evaluate proposed capital investments. Copperleaf allows EGI to optimize its investment portfolio based on the defined capital considerations (see **Section 6.1.2**), use a normalized scale to support value-based decision-making, and helps to ensure EGI fulfils its regulatory and internal requirements for systematic and transparent investment decisions.

Copperleaf supports the AIPM process (see **Section 4.3**) by:

- Allowing the documentation of risk management opportunities and treatment options
- Capturing growth opportunities
- Providing context on value-driven investments through the value framework, to demonstrate alignment with the Asset Management Policy and organizational strategic priorities
- Performing portfolio optimizations using iterative scenarios to determine an optimal spend profile
- Allowing investment details to be updated throughout the year to optimally manage the investment portfolio
- Providing full transparency to business stakeholders on the approved work plan and understanding year-over-year changes

For value-driven investments (see **Table 4.1-2**), an organization needs a mechanism to determine its investments' relative value. 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 additions

An investment's value is quantified through Copperleaf's value framework or evaluated via the GDS Risk Management process. The investment timing and scope of work for investments that rely on the GDS Risk Management process is typically more complex–investment timing is confirmed outside of Copperleaf optimization. For value-driven investments that use the Copperleaf value framework, value measures are used to quantify an investment's value, as described in **Table 4.1-3**.

Value measures are investment attributes that are evaluated objectively based on risk or opportunity to determine how the investment delivers value to Enbridge and the ratepayer. These value measures are placed on an economic scale to assist in optimization. An investment's net value is used to determine both its independent merit and its standing among other investments in a constrained optimization process.

The **Copperleaf value framework** is an analytical framework that complements risk assessments, allows for comparison of dissimilar investments and enables portfolio optimization. Each of the Enbridge's strategic priorities (see **Section 2.2.2**) is comprised of one or more value measures. For more details on valuing investment risk, see **Section 4.2.3**.

Table 4.1-3: EGI's Value Measures

Value Measure	Description
Employee and Contractor Health and Safety Risk	Measures the risk of employee and contractor safety incidents that will be mitigated through the completion of an investment.
Public Health and 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 CO_2 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/unplanned). Cost avoidance measures are never reflected in financial 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/unplanned). 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.

Value Measure	Description
Energy Efficiency	Measures the financial benefits through annual energy savings and reduced CO_2 emissions.
Employee Productivity	Measures the impact on working conditions and employee productivity.

EGI has been implementing and continues to mature its asset management decision-making practice.

4.1.6 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 (see **Figure 4.1-6**). Asset analytics supports people, processes 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 using data that is fit for purpose.

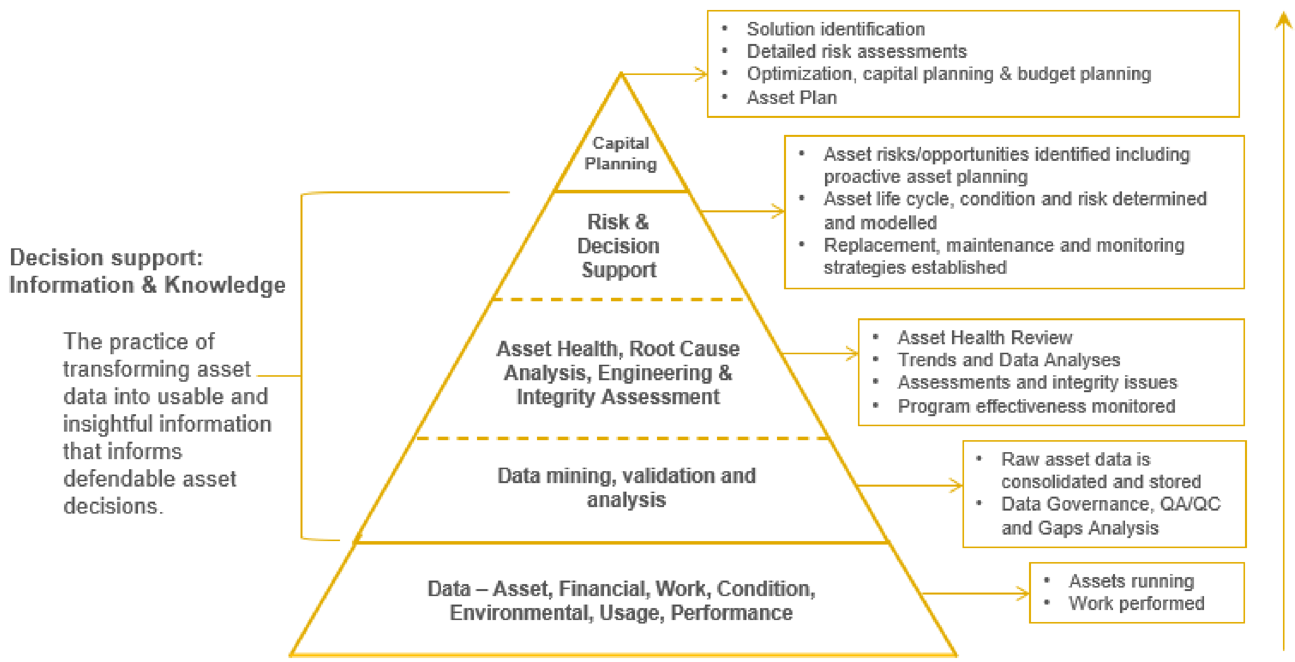


Figure 4.1-6: Asset Information and Support to Asset Investment Planning

Asset data enables the evaluation of existing assets, determines patterns, supports costing of solution options and identifies meaningful information to inform life cycle management strategies. Several reports and tools are used to inform asset investment planning. Supported by EGI and industry knowledge, asset information is leveraged for asset analytics and modelling to:

- Assess asset condition
- Support and predict risk and value assessments
- Develop cost estimates and understand financial performance
- 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

4.2 Risk Management

A risk is defined as the negative impact of uncertainty on the organization's objectives expressed as the combination of the likelihood and consequence of a potential event. To manage risk, the Risk Management process, which is consistent with *ISO 31000* (see **Figure 4.2-1**), involves a series of activities designed to help the organization assess, prioritize and treat risks.

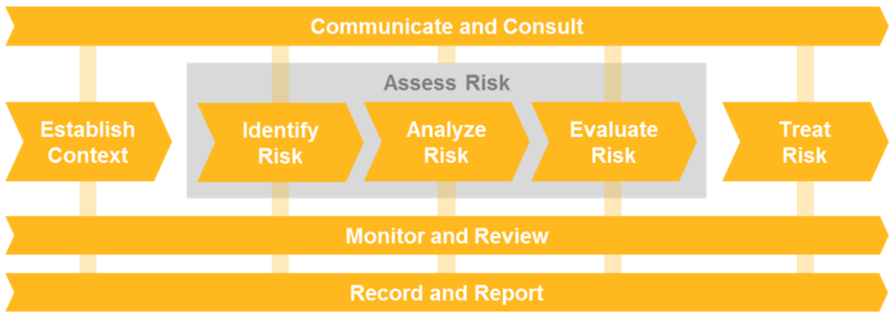


Figure 4.2-1: Enbridge Risk Management Process

The following sections provide more detail about the process steps and the roles involved in Risk Management at EGI.

4.2.1 Identify Risk

Operational hazard and risk identification occur throughout the asset life cycle and are identified through:

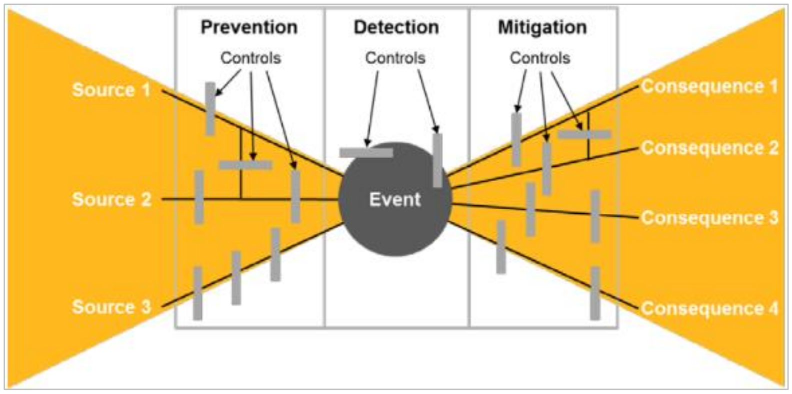
- Internal sources such as databases, frontline processes, targeted reviews, assessments and meetings
- External sources such as published industrial incidents, industry-related publications distributed by regulatory bodies and industry associations, local governments, external crime statistics, industry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

4.2.2 Analyze Risk

Risk factors shown in the Risk Bowtie Model (see **Figure 4.2-2**) are analyzed and assessed. The commonly used types of risk assessments at EGI are quantitative, semi-quantitative and qualitative which are described in **Table 4.2-1.** The selection of the approach is dependent on the scope of the assessment, maturity of risk assessment technique, best available data and information at the time of the assessment and the types of assets.

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 judgment, experience and technical knowledge.	Used to identify and understand risk factors.
Quantitative Approach	Detailed technical assessments that leverage numerical data and mathematical methods to quantify risks.	Applied to contexts which are well understood and where numerical data and mathematical models can be used to quantify risk factors.
Semi-Quantitative Approach	Relies on qualitative inputs, such as expert judgment, 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.



Source: Adapted from IEC/ISO 31010 (2009)

Figure 4.2-2: Risk Bowtie Model

In order to provide clear guidance on prioritizing resources on managing risks, the EGI Risk Evaluation Framework (see **Figure 4.2-3**) is applied. When a risk is assessed to be in Region 1, risk treatment must be taken to reduce risk to all practicable extent. The timing of risk treatments to reduce risk may vary by scenario with reduction occurring as soon as possible while following applicable standard operating procedures and related business processes and requirements. Risk in Region 2 must be treated unless it can demonstrate that the risk has already been reduced as low as technically and economically feasible. Region 2 acknowledges that there are practical limits to ability to reduce risk. Risks in Region 3 do not require further treatment but, like risks in other Regions must be monitored according to applicable procedures and related businesses' processes and requirements.

The framework ensures that resource allocations are prioritized to EGI's higher risks to ensure safe and reliable operations. It also ensures the ability to demonstrate that all reasonable measures have been undertaken to reduce risk.

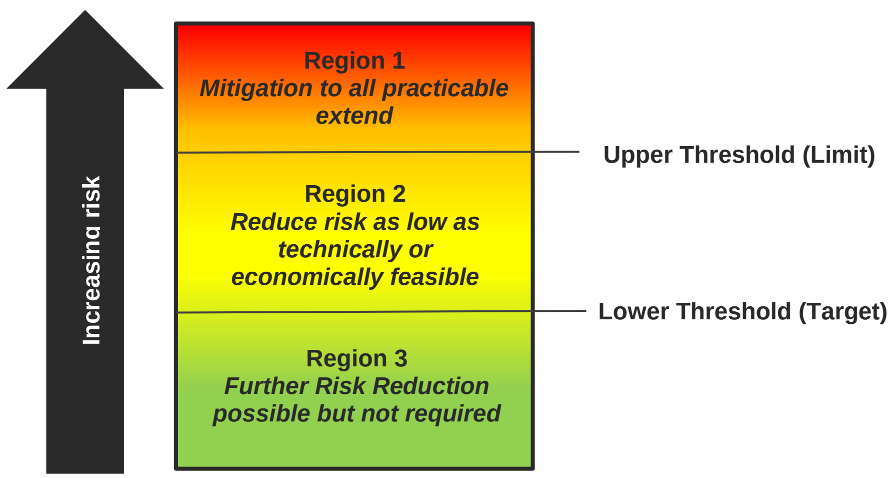


Figure 4.2-3: EGI Risk Evaluation Framework

As EGI evolves its risk management practices, two approaches have been adopted from industry best practices; Enbridge Risk Matrix (see **Figure 4.2-4** where the Y-axis indicates likelihood, and the X-axis indicates consequence) and risk thresholds (upper and lower thresholds) as illustrated in **Figure 4.2-3**.

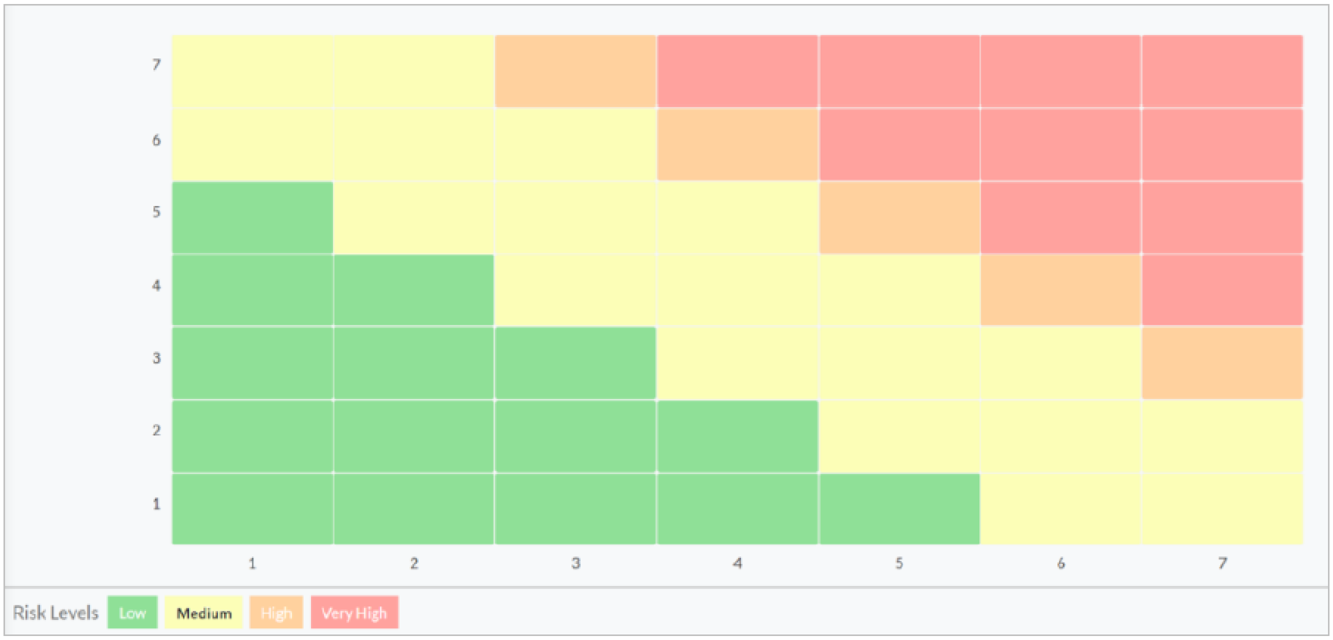


Figure 4.2-4: Enbridge Risk Matrix

In most cases, the risk matrix is used to support comparison of risks across multiple dimensions where risks are estimated in terms of likelihood and consequence with results being plotted on the matrix. The EGI Risk Evaluation Framework (see **Figure 4.2-3**) and the Enbridge Risk Matrix (see **Figure 4.2-4**) are complementary and support risk informed decision-making.

Sometimes there is a need to understand safety risks due to release of hazardous materials such as flammable and toxic material and their intersection with the public and employees, also known as catastrophic/rare events. In such cases, risk quantification can be applied, provided there are data and analytical techniques to allow for this.

The safety risk evaluation criteria proposed by the Risk Management Task Force (RMTF) (formed by the CSA under the Technical Committee for Z662 Standard on the Oil and Gas Pipeline System) are used for this type of assessment, the criteria have also been adopted by UK Health and Safety Executive (UK HSE). This approach is also in use at major North American energy companies[3]. These criteria are represented by lower and upper thresholds (i.e., target and limit) as shown in the EGI Risk Evaluation Framework (see **Figure 4.2-3**).

While the EGI Risk Evaluation Framework can support treatment prioritization and risk reduction, ultimately, the actions EGI takes in the face of specific risks are influenced by many factors including the business environment, regulatory, planning, financial, commercial, stakeholders and the quality and maturity of risk assessment data and capabilities. The risk assessment and decision to treat a risk are inputs to the Asset Investment Planning and Management process (see **Section 4.3**).

4.2.3 Evaluate Risk

Having analyzed the risk, the EGI Risk Evaluation Framework (see **Figure 4.2-3**) is used to provide guidance on prioritizing resources on managing risks. For more details on Risk and Review, see **Section 4.1.4**. Once decisions are made to treat risks, they are documented with treatment plans as part of the Risk Management process. Depending on the nature of the risk, these risks may be reported quarterly through EGI's Integrated Management System processes.

The level of uncertainty of a risk evaluation needs to be considered and can influence the confidence in likelihoods and consequences of specific scenarios. Where level of uncertainty is higher it may be necessary to further augment quantitative assessments with qualitative considerations.

[3] Tomic, Aleksandar, Kariyawasam, Shahani, "Critical Review of Risk Criteria for Natural Gas Pipelines", Proceeding of the 2016 11th International Pipeline Conference IPC 2016-64356, Calgary, AB, September 26-30, 2016.

4.2.4 Treat Risk

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 required 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 Operate and Maintain phases of the asset life cycle.

Figure 4.2-5 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 reliability centered maintenance study or Original Equipment Manufacturer (OEM) recommendations. These risk treatment options are considered during the Solution Planning and Value Assessment stage (see **Section 4.3.2**) of the AIPM process.

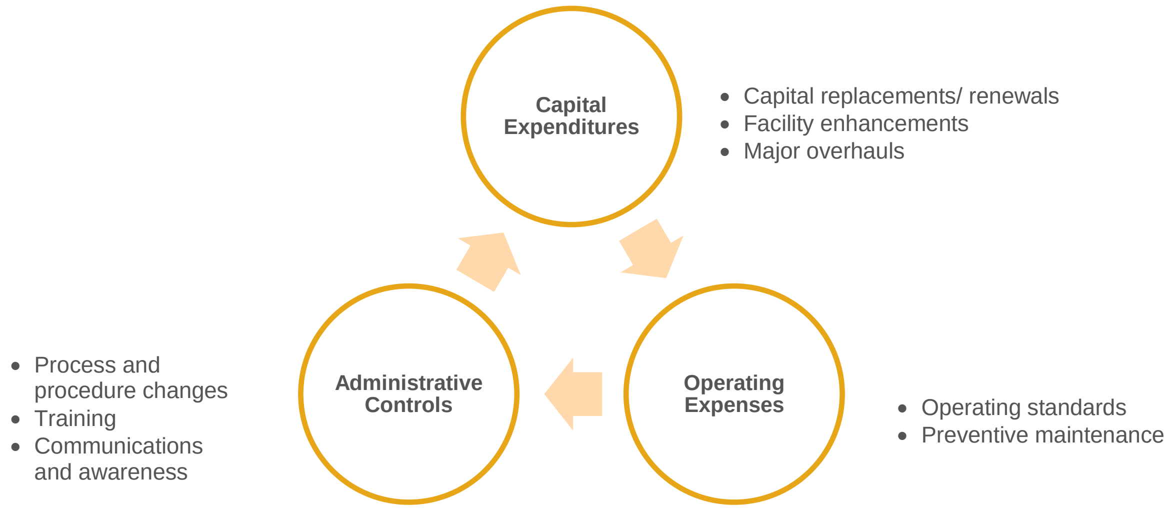


Figure 4.2-5: Spectrum of Risk Treatment Options

4.2.5 Monitor and Review Risk

EGI maintains a risk register to communicate and review all operational risks. Risks are reported and reviewed on a quarterly basis through a risk reporting process. Each management program owner within the Integrated Management System and each risk owner is also accountable for the ongoing management of risks within their accountabilities.

4.3 Asset Investment Planning and Management (AIPM) Process

Within the overall Asset Management Strategic Framework, as capital investment needs are identified, they are evaluated and executed through the Asset Investment Planning and Management (AIPM) process (see **Figure 4.3-1**). **Figure 4.3-1** represents the current state AIPM process that was used to develop the 2023-2032 Capital Portfolio and Appendix B - IRP, the future state AIPM process will incorporate the IRP Assessment process at the Solution Planning & Value Assessment stage.

Figure 4.3-1: EGI AIPM Process

4.3.1 Identify Investment Need

Capital investment needs enter the AIPM process via EGI's asset investment planning tool (Copperleaf). An investment need is either a risk or opportunity to the organization. The investment need can be entered directly into Copperleaf, or it may arise through the Risk Management process (see **Section 4.2**) once an identified risk is determined to require capital treatment. The following investments are entered directly into Copperleaf:

- Growth and cost-saving opportunities
- Compliance investments
- Ongoing programmatic spend with sufficient history and risk to warrant continuation

Once an investment need is captured in Copperleaf, the asset manager validates that the need aligns with the strategies for the asset class and that a capital investment is required. Once confirmed that a capital investment is indeed required, solution planning and value assessment (if applicable) can begin.

Depending on the required timing to address the identified investment need with a solution, an investment may be considered for portfolio optimization or may be considered emergent, where it is approved off-cycle from budgeting activities; emergent investments require capital within the current year and are reviewed case-by-case by the asset manager and Asset Management Governance.

4.3.2 Solution Planning and Value Assessment

Solution planning is initiated once an investment need is approved by the asset manager and can occur in parallel with the completion of a value assessment (when required). A Copperleaf investment contains a scope, cost estimate and preferred timing for all identified solutions (facility and non-facility) to address the need. Investments can be in the form of a **Project** or a **Program**, as described in **Table 4.3-1**.

Table 4.3-1: Project and Program Descriptions

Investment Type	EGI Description
Project	A one-time individual initiative with a distinct scope and timeline.
Program	An overarching 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 Asset Management Plan. Cost estimates 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 and captured in the value assessment. All estimates are based on current year costs (except for programs that have a defined scope). 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 (see **Table 4.3-2**). 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 allocated on a project-by-project basis based on asset class, project risk and scope of work.

Table 4.3-2: 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

All value-driven investments have their value assessed in Copperleaf once a scope and cost estimate have been defined. Where there is more than one option to address a risk or opportunity, each option is value assessed. The value assessment quantifies the amount of risk reduced and any value gained by the proposed solution option based on the value measures defined in **Table 4.1-3**. The combination of value measures and investment cost is referred to as the total investment value, which is used to prioritize investments in optimization. While the value measures will differ between investments and solution options, the total investment value allows comparison of dissimilar investments.

4.3.3 Optimize Portfolio of Solutions

With solution planning and value assessment complete, portfolio optimization is performed in Copperleaf, where a multi-year investment plan is created based on asset management principles. Prior to optimization, proposed investments are reviewed with business stakeholders to ensure all known risks and opportunities to the organization are captured. The portfolio is then optimized to determine the optimal investment timing for investments that have flexible timing, with constraints on the annual net direct capital and consideration of available resources.

A 10-year time frame 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 outer half of the 10-year span. For this reason, programmatic spend is proposed to address risks, where projects are continually defined and attached to programs as scope refinement occurs.

Once all investments are categorized based on **Table 4.1-2,** portfolio optimization begins. Investments identified as mandatory, compliance, or value-driven using the Risk Management process are automatically slotted at the required time rather than using risk and cost to determine optimal timing. Value-driven investments using the Copperleaf value framework are free to shift within the optimization time frame.

Prior to optimizing, an initial portfolio representing the preferred option and timing of investments is captured. This typically results in an inconsistent spend profile over the 10 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 spends at the organization
- Risks that must be treated because they exceed a threshold in EGI Risk Management process (see **Section 4.2**)
- Asset life cycle strategies
- The original proposal of work (preoptimization) and an understanding of the associated compliance and mandatory projects/programs

Using Copperleaf, the EGI portfolio is optimized and analyzed by varying the net direct capital per year, highlighting the effects of project timing, option selection and value. The results from these scenarios are reviewed with asset managers to find the combination of investment options and start dates that best meet business needs within specified constraints. This scenario is 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.

4.3.4 Produce Capital Portfolio

The capital portfolio is captured in Microsoft Excel as well as Copperleaf. This provides business stakeholders with broad access to the approved capital plan and encourages working on a multi-year plan. The use of Copperleaf enables ongoing refinement of investments in the plan and periodic review of changes and updates to understand their impact.

4.3.4.1 IRP Assessment Process

Once the capital portfolio is produced, EGI uses an IRP assessment process, which includes a binary screen and an IRPA evaluation, to determine the best approach to meet identified system needs/constraints. In a project-specific application (Leave to Construct or IRP Plan), EGI demonstrates that it has followed this process including the results of the analysis at each of the following stages:

1. Identification of Constraints
2. Binary Screening Criteria
3. Two-Stage Evaluation Process
4. Periodic Review

EGI is beginning to integrate the IRP assessment process into its annual planning activities. With 2022 being the first year that EGI has implemented the IRP assessment process, the projects are evaluated after the Produce Approved Capital Portfolio (see **Section 4.3.4**) step in the AIPM process. Once EGI has completed the review of projects in this Asset Management Plan, the process will be adjusted to occur as part of Solution Planning and Value Assessment (see **Section 4.3.2**). It is anticipated that over the next couple of years the IRP assessment process is expected to occur during both Stages 2 and 4 of the AIPM process, in order to ensure all projects have been assessed and reevaluated as required. The result of EGI's IRP Assessment Process is summarized in **Section 6.3**.

4.3.5 Execute Annual Portfolio Plan

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 (increases or decreases) to the current portfolio. As these pressures are identified, trade-off decisions are made based on value and available capital, a direct demonstration of EGI's Plan-Do-Check-Act cycle (see **Figure 3.0-2**).

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 portfolio. 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.

4.3.6 AIPM Performance Review

Performance measurement provides insight into assets, asset management performance and the effectiveness of the asset management system. To determine AIPM performance, 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 (see **Section 5**)
- Accomplishment of specific asset management objectives

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 (see **Section 5**).

The **Asset Management Health Check** 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 management program health check will inform senior management of the effectiveness of the Asset Management team in maturing the Asset Management Program.

5 Customers and Assets

This section provides details on the following:

- EGI's customers and the customer growth projections
- Asset class objectives, risks and opportunities
- Asset inventory and condition
- Asset class strategic plans to meet life-cycle strategies

In **Figure 4.3-1**, it can be seen that natural gas delivers a significant portion of Ontario's energy needs on both a peak and average basis. EGI provides this energy safely, affordably and reliably, and is committed to delivering this energy with net-zero operational emissions by 2050. EGI also contributes positively to the low-carbon economy through its investments in innovative low-carbon solutions such as hydrogen and renewable natural gas. In addition, when compared with electricity, natural gas continues to be cost-effective, delivers approximately two times the energy and over four times the peak demand, through underground infrastructure that is less susceptible to the weather events that impact electrical infrastructure, offering much needed resiliency.

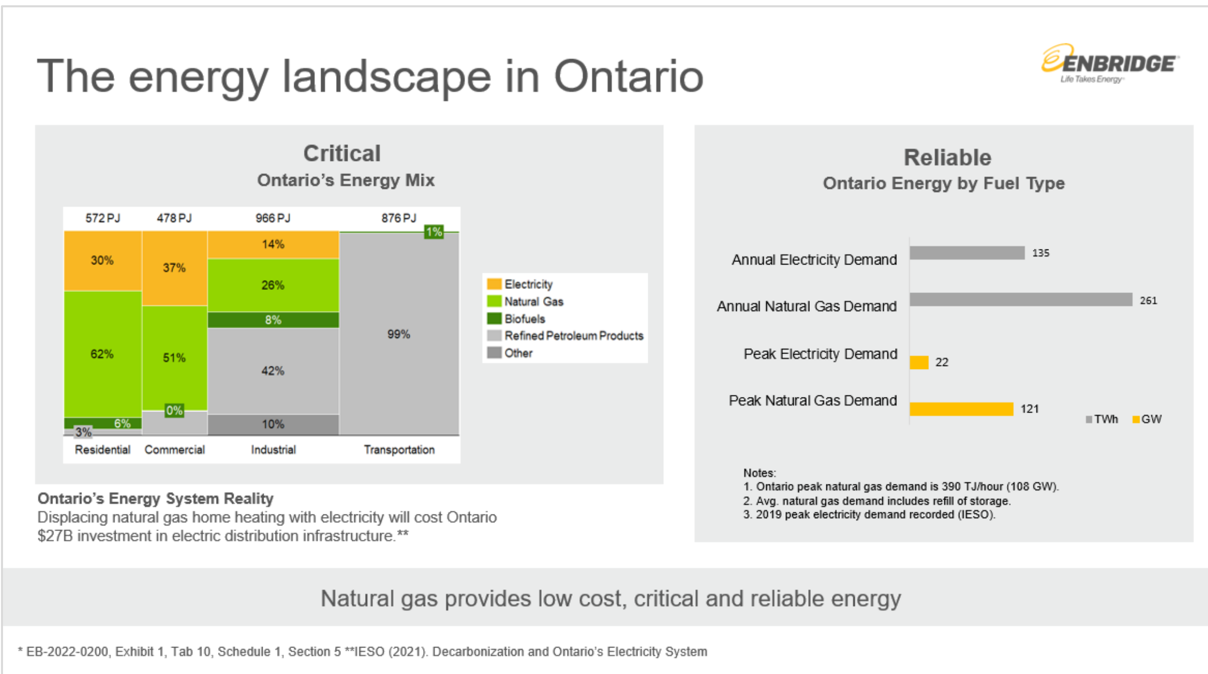


Figure 4.3-1: The Energy Landscape in Ontario

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 assets that serve to receive, store, transport and distribute energy. **Figure 4.3-2** shows how these assets and those that support them are interconnected to provide safe and reliable natural gas to EGI's customers.

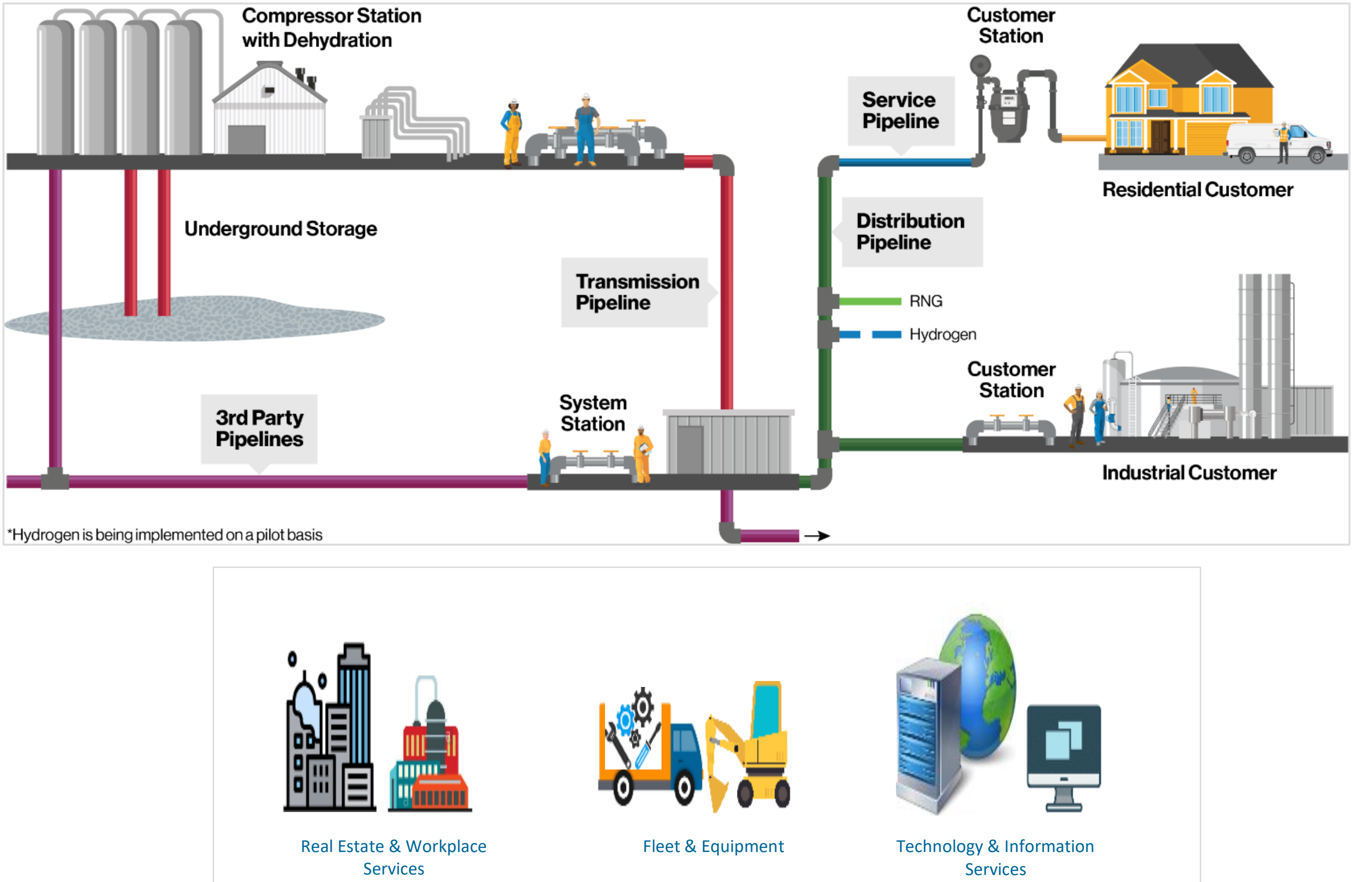


Figure 4.3-2: Components of a Natural Gas System and Supporting Assets

5.1 Growth

EGI delivers safe and reliable natural gas to over 3.8 million customers, and this customer base is forecast to grow over the 10-year period of this Asset Management Plan. EGI services residential, apartment, commercial, industrial and transmission customers within its franchise areas. As practical, verifiable and prudent alternatives are available, the Growth asset class will continue to evolve to incorporate low-carbon technologies and implement energy transition and IRPAs.

The Growth asset class consists of assets to serve 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. EGI continues to connect customers with natural gas service within its franchise area, consistent with the requirements of *EBO 188* while also considering Integrated Resource Planning alternatives (IRPAs). The Growth asset class is divided into five subclasses:

- **Customer Connections** activity 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. The IRP Assessment Process is used to evaluate the preferred solution to meet the specific system needs (see **Appendix B – IRP**).
- **Community Expansion** projects involve the installation of gas distribution assets to serve communities that have not previously had access to natural gas and that are not feasible without funding support. These projects are driven by municipal and/or community interest and supported by an Ontario Energy Board (OEB)-approved funding mechanism of a System Expansion Surcharge (SES) from all connected customers as well as government-approved ratepayer-supported funding under *Bill 32: Access to Natural Gas Act, 2018.*
- **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 increasing in-franchise and ex-franchise demand growth. Capital costs related to transmission system reinforcements are included in the expenditure summary for the Transmission Pipe and Underground Storage asset class (see **Section 5.3.6.4**). The IRP Assessment Process is used to evaluate the preferred solution to meet the specific system needs (see **Appendix B – IRP**).
- **Hydrogen Blending** projects look for ways in which EGI can reduce GHG emissions through the introduction of hydrogen into the natural gas distribution system and other company assets. With the Q4 2021 in-service date of the Markham Hydrogen Blending Pilot Project (approximately 2% of the gas stream by volume), EGI operates the first North American hydrogen blending facility. Engineering has monitoring standards in place to ensure safe and reliable operations. As hydrogen blending matures and evolves, strategies for maintenance and replacement of existing infrastructure 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.

The Growth capital expenditure requirements for materials and asset installation is based on forecast customer growth over the next 2023-2032. To account for the evolving energy transition, reinforcement projects are screened and analyzed in accordance with the IRP Framework (EB-2020-0091 [Appendix A]) and best available energy transition related information. Capital expenditure requirements related to the condition of existing assets (mains, services, measurement, and regulating equipment, etc.) are addressed in the **Distribution Operations** and **Storage and Transmission Operations** asset classes.

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 5.1.1-1**.

Table 5.1.1-1: Growth Asset Class Objectives

Asset Class Objectives	Description
Integrated Resource Planning	Screen projects using EGI's IRP assessment process; for those that pass, determine if there are IRPAs that are economically and technically feasible.
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 when projects do not pass IRP Binary Screening or where IRPAs are not feasible.
	Reinforce distribution networks and transmission systems to economically serve short- and long-term demand requirements where projects do not pass IRP Binary Screening or where IRPAs are not feasible.
System Integrity and Reliability	Reinforce existing transmission pipeline systems and distribution networks to ensure capacity and reliably meet current and future customer demand where projects do not pass the IRP screening or where IRP alternatives are not feasible.

The performance measures for the Growth asset class are:

- Number of networks forecast through the long-range planning process to drop below minimum operating pressure
- Number of customer additions
- Number of investments screened using the IRP assessment process and for those that pass the IRP Binary Screening, the number of investments evaluated to determine if there are economically and technically feasible IRPAs.

To achieve the Growth asset class objectives listed in **Table 5.1.1-1**, asset investment decisions are governed by the life-cycle management strategies outlined in **Table 4.1-1**.

5.1.2 Growth Hierarchy

See **Section 4.1.3** for the asset life cycle, for which growth is a key component of the Design/Construct stage. After design/construction of the growth asset as depicted in **Figure 5.1-1**, these assets are operated, maintained, and renewed/retired within the Distribution Operations and Storage and Transmission Operations asset classes.

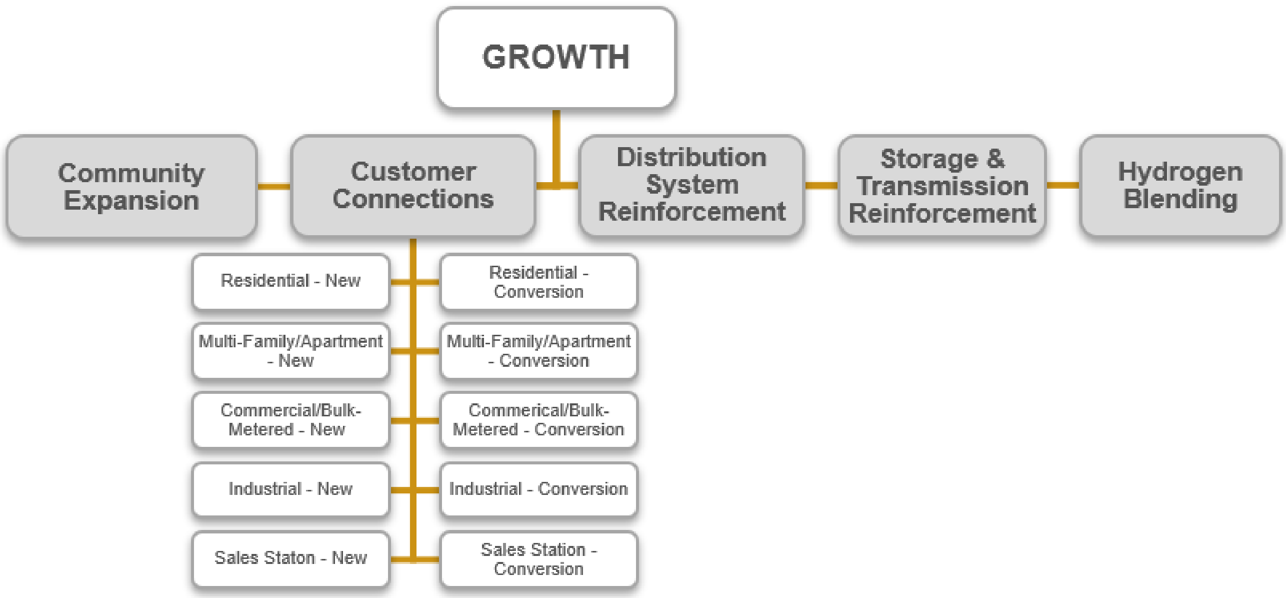


Figure 5.1-1: Growth Hierarchy

5.1.3 Growth Strategy Overview

Table 5.1.3-1: Growth and Hydrogen Condition and Strategy Overview

Asset Program	Growth Forecast	Risk / Opportunity	Strategy
Customer Connections	**Figure 5.1-2** and **Figure 5.1-3** show the customer growth forecast for the EGD and Union rate zones respectively.	EGI is expected to provide new or upgraded natural gas services to residential and commercial/industrial customers (*EBO 188*), where the project is feasible, determined by quantifying the value of a project's revenues against its costs (the Profitability Index [PI]).	The strategy for Customer Connections 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, which considers the impact of energy transition. Economic feasibility for growth is based on *EBO 188* guidelines applied to the investment portfolio and rolling project portfolio.
Distribution System Reinforcement	To identify purpose, need and timing of distribution system reinforcements, EGI utilizes peak hourly consumption to determine distribution system needs.	Ensure security of distribution system capacity to meet the needs of existing customers and support forecasted customer growth using *EBO 188* guidelines, and in accordance with the IRP Framework.	All reinforcement projects will be subject to a Binary Screening through the IRP assessment process. IRP, as prescribed by the OEB, will allow for non-pipe alternatives to be thoroughly examined, reviewed, and implemented where economically and technically feasible. The strategy for the Distribution System Reinforcements is to continue to ensure the installation of infrastructure required to enable the addition of all forecasted customers feasible under *EBO 188* guidelines, for those that do not pass IRP screening or where IRPAs are not feasible, while following current forecasting practices, which considers the impact of energy transition.
Community Expansion	Through Phase Two of the Natural Gas Expansion Program, EGI was awarded ~$214M to support 27 Phase 2 Natural Gas Expansion Projects (NGEP) projects.	Community expansion is a growth opportunity to provide natural gas services to communities not currently being serviced by EGI.	EGI's Community Expansion Strategy is to continue assessing and pursuing opportunities to provide gas distribution service to under-served communities. Application opportunities for project funding are dictated by the government under *Bill 32: Access to Natural Gas Act, 2018.*
Transmission System Reinforcement	To identify purpose, need and timing of transmission system reinforcements, EGI annually completes a design day demand forecast that is used to identify short- and long-range plans through model simulation.	Ensure safe and reliable transmission system operations and support increasing in-franchise and ex-franchise demand growth using *EBO 134* guidelines, and in accordance with the IRP Framework.	All reinforcement projects will be subject to a Binary Screening through the IRP assessment process. IRP, as prescribed by the OEB, will allow for non-pipe alternatives to be thoroughly examined, reviewed, and implemented where economically and technically feasible. The strategy for the Transmission System Reinforcements is to continue to ensure that required infrastructure is installed to enable the addition of all forecasted customers and distribution growth feasible under *EBO 134* guidelines, for those that do not pass IRP screening or where IRPAs are not feasible, while following current forecasting practices, which considers the impact of energy transition.
Hydrogen Blending	EGI continues to evaluate the extent that hydrogen can be used in the distribution system and company assets.	The successful operation of the pilot project requires regulations and standards for hydrogen to be harmonized by governments and regulatory agencies and for hydrogen to be cost-competitive.	EGI continues to evaluate the extent that hydrogen can be used in the distribution system and company assets. EGI will apply learnings from its Hydrogen Blending pilot projects and its hydrogen blending facility in Markham to allow it to further Canadian leadership on hydrogen development and a low-carbon future. EGI continues to collaborate with governments and partners to advance innovative energy solutions to keep energy reliable, affordable and reduce environmental impact.

5.1.4 Customer Connections

The Customer Connections subclass consists of assets to serve 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, and regulating equipment.

EGI expands its distribution system in accordance with the OEB's guidelines for the expansion of natural gas service and the IRP Framework. 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. For details on these requirements, see **Section 5.1.5**.

Capital investments, such as material and labour costs, are required to support new customer connections. For details on the capital investment forecast, see **Section 5.1.4.2**.

Each year, EGI develops a customer growth forecast using a number of information sources. For details on this process and projections, see **Section 5.1.4.3**.

5.1.4.1 Customer Connections Feasibility

EGI uses a portfolio approach (Investment Portfolio and Rolling Project Portfolio) to manage system expansion activities and ensure 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 forecast 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 PI of the project based on its future revenues versus the costs.

The PI 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 RPP. EGI is experiencing increased costs to add customers as a result of inflation and increased safety requirements – for example, line locates and changes to construction practices to reduce the likelihood of sewer lateral cross bores.

5.1.4.1.1 FEASIBILITY PROCESS

When assessing the feasibility of a new project, EGI prepares a forecast of 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.

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).

5.1.4.1.1.1 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 in *EBO 188*. Starting in 2021, the OEB approved an alternative, known as the Temporary Connection Surcharge (TCS), to CIAC which allows customers to contribute with a portion of their savings over time.

Benefits: The project revenues are based on an estimate of the monthly customer 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 and meter sets), labour and equipment to install or construct the project and reclamation of the surface (such as road, sidewalk, landscaping).

Indirect costs for a project may include planning and design costs, gas distribution network capacity costs and administration costs attributable to customer growth such as inventory management.

5.1.4.2 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, four 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 includes:

- Attachments for residential subdivisions (New)
- Residential replacement, i.e., fuel conversions of existing homes (Conversion)
- Commercial buildings (New and Conversion)
- Multi-family/apartment (New and Conversion)
- Industrial facilities (New and Conversion)

5.1.4.2.1 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. Based on the historical spend in each area, combined with forecast customer additions and inflation, the 10-year capital expenditure forecast is determined. The capital requirement includes an allowance for some localized main extensions and operational considerations.

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.

5.1.4.3 Customer Connections 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. Development of this forecast considers attachments, additions and conversions including detailed information originating from direct contact with builders, developers and municipalities. 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 5.1-2 and **Figure 5.1-3** show the customer 2022 Long Range Plan (LRP) growth forecast for including energy transition (ET) assumptions for EGD and Union rate zones respectively (for detail on ET assumptions, refer to Exhibit 1, Tab 10, Schedule 4). The 2023-2032 customer connections capital expenditure (see **Table 5.1.10**) was informed by the 2022 LRP forecast (without ET assumptions), this was the most current forecast available at the time of optimization. When the 2022 LRP including ET forecast was produced, EGI compared it to the 2022 LRP forecast without ET assumptions. The comparison showed that the ET assumptions reduced the capital expenditure forecast by ~$60k in 2024 and by ~$44M over the 2024-2028 rebasing period. EGI did not revise the AMP's capital expenditures to reflect the forecast with ET assumptions as the impact was minimal over the rebasing period and there was insufficient time for rework.

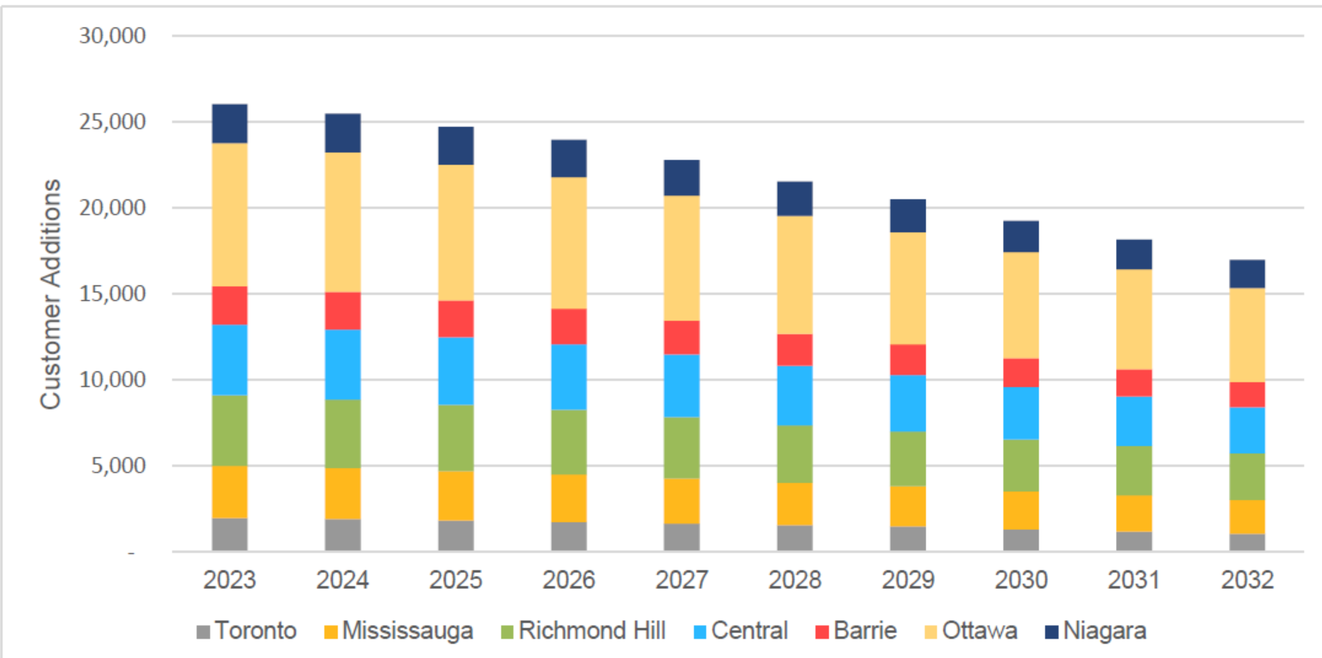


Figure 5.1-2: 10-Year Customer Growth Forecast - EGD Rate Zone[4]

[4] Based on 2022 LRP with Energy Transition Assumptions

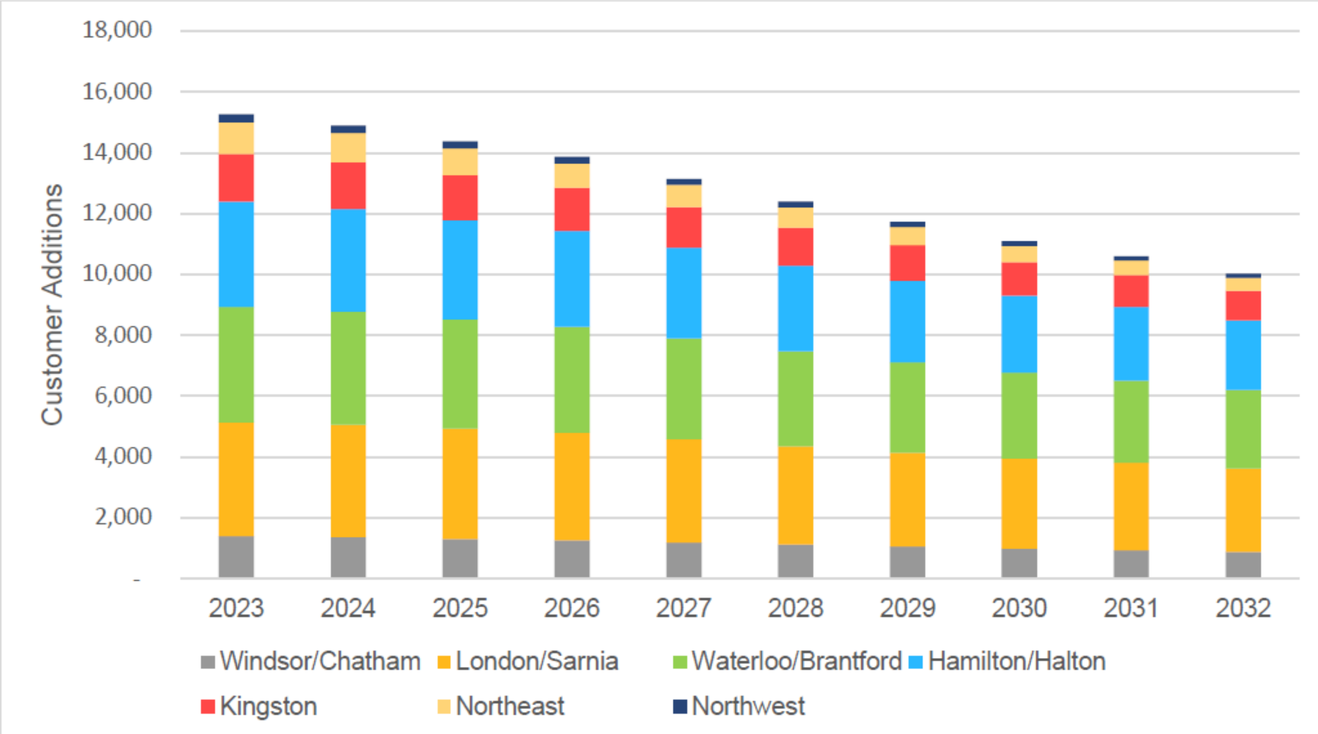


Figure 5.1-3: 10-Year Customer Growth Forecast - Union Rate Zones[5]

Over the 10-year forecast, the number of customer connections decline when factoring in energy transition. Customer additions, connections and growth 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.

[5] Based on 2022 LRP with Energy Transition Assumptions

Based on the methodology described in **Section 5.1.4.2.1**, **Figure 5.1-4** and **Figure 5.1-5** represent the forecast number of customer additions over 10 years by sector.

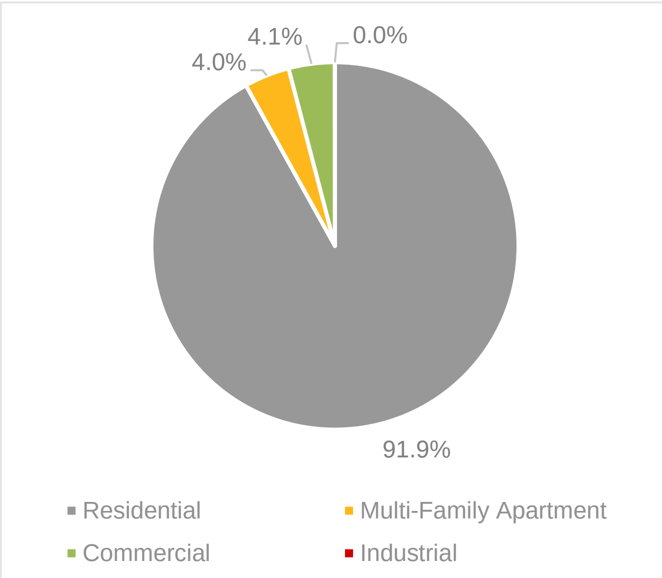


Figure 5.1-4: Growth Forecast by Customer Type – EGD Rate Zone (Includes Energy Transition Forecasting)

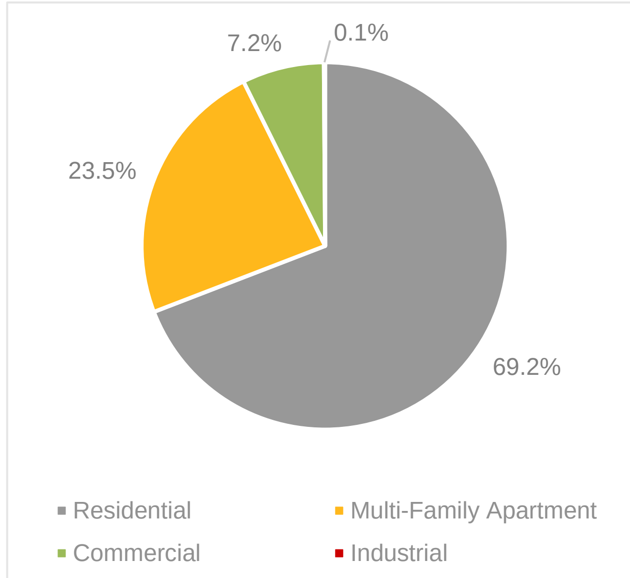


Figure 5.1-5: Growth Forecast by Customer Type – Union Rate Zones (Includes Energy Transition Forecasting)

The customer additions by sector reflect continued residential growth over the forecast period in both the residential subdivision and residential replacement (conversion) markets. Over the 10-year forecast, the pace of growth declines when factoring in energy transition.

5.1.5 Distribution System Reinforcement

Distribution System reinforcements refer to asset investments required to maintain minimum system pressures, so that demand for gas can be met on design day conditions. These investments must meet the requirements of *EBO 188* (see **Section 5.1.4.1**) or *EBO 134* as applicable. Details on the process for identifying and planning these investments are in **Section 5.1.5.1**. In accordance with the IRP Framework (EB-2020-0091), the IRP assessment process is used to evaluate the preferred facility solution compared to IRPAs to meet the specific system needs (see **Appendix B – IRP**).

Distribution System reinforcement projects involve the installation of new infrastructure 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 forecast customers during peak design 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 forecasting 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 the Peak Day Peak Hour Methodology described in Exhibit 4, Tab 2, Schedule 3.

5.1.5.1 Distribution System Forecasting Methodology

EGI completes an annual simulation and verification of hydraulic models using pressure and flow measurement on the system during peak conditions experienced in that year. This provides a reliable, and repeatable process for estimating general demand on the distribution system. For many large volume customers, hourly data is available, and these loads are included within the analysis.

For long-range system planning, EGI uses operational input, economic factors and energy transition assumptions (Exhibit 1, Tab 10, Schedule 4), as well as data from builders, developers, municipalities. Together, this information will establish the future loads on the system, including the resultant need, timing, location and scope for distribution system reinforcement. EGI utilizes the IRP assessment process to screen the identified needs; and for those that pass the binary screening, a technical and economic evaluation of IRPAs is completed (see **Appendix B – IRP**). This leads to the creation of a reinforcement plan to sustain the 10-year customer growth forecast.

5.1.5.2 Risk and Opportunity

Distribution system reinforcement projects identify areas of the distribution network where there is risk of not having the required capacity to meet the peak hour demands of EGI's customers or 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 and efficiencies in operation. This aligns with the 2024 Rate Rebasing Customer Engagement results which indicate 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 5.1.4.1** provides further details on *EBO 188* guidelines for feasibility purposes.

To meet *EBO 188* requirements, a preliminary feasibility analysis is conducted using cost estimates, customer addition forecasts and discounted cash flow assumptions. This analysis determines the aggregate cost-benefit ratio for all reinforcement projects that are proposed as part of the System Reinforcement Plan (SRP). Overall, the projects proposed in this plan are in the acceptable feasibility range for inclusion in this Asset Management Plan.

In addition to EBO 188, EGI uses the IRP assessment process to complete a binary screening of reinforcement projects, and for those that pass binary screening, a technical and economic evaluation of IRPAs is completed (see **Appendix B - IRP**).

5.1.6 Community Expansion

Community Expansion projects involve the installation of gas distribution assets to serve communities that have not previously had access to natural gas and that were not previously feasible without funding support. These projects are driven by municipal and/or community interest and supported by an OEB-approved funding mechanism of a SES from all connected customers as well as government-approved ratepayer supported funding under *Bill 32: Access to Natural Gas Act, 2018.* Community expansion projects range in size, customer capture, and geography to extend the gas network within an existing served municipality or into an entirely new community. The Community Expansion Program expenditures do not meet current EBO 188 economic feasibility guidelines without a rate rider. Because the projects are contingent on funding support to make them feasible, acquisition of new projects into the program is dictated by government allocation of funding to support expansion which has been released in phases under the current *Bill 32*. The Community Expansion Program expenditures do not pass the IRP Framework's binary screening and, therefore, do not require a technical or economic evaluations of IRPAs.

In addition to government-approved funding, an ES is also applied to every customer attaching to the new network to be paid over a maximum term of 40-years. The OEB issued a decision November 2020 approving a harmonized ES between Union and EGD stipulating project parameters including a 10-year rate stability period for forecasted attachments and an ES term of up to 40-years (see EB-2020-0094).

Bill 32 Background

EGI has several community expansion projects completed or underway, made possible through Phase 1 of the Natural Gas Support Program, which was announced in March 2019 with allocated funding of approximately $56M. These projects included bringing natural gas to the communities of Chippewas of the Thames First Nation, North Bay-Northshore and Peninsula Roads, Saugeen First Nation, and Scugog Island, with two projects still in consultation including Cornwall Island and Hiawatha First Nation. EGI has also brought natural gas to Fenelon Falls and Moraviantown First Nation, made possible with funding provided by the Government of Ontario's previous Natural Gas Grant Program.

In December 2019, the Government of Ontario announced it is continuing to expand access to safe, reliable, and affordable natural gas to rural, northern and Indigenous communities. The Government of Ontario requested that interested parties submit proposals on potential community expansion projects. The OEB evaluated the proposals and submitted its report to the Ministry of Northern Development and Mines (MENDM) by October 31, 2020. The MENDM reviewed the OEB's report and used it as an input to make project selections.

In June 2021, the Government of Ontario announced funding for community expansion and economic development projects under Phase 2 of the Natural Gas Expansion Program. EGI was awarded ~$214M to support 27 Phase 2 NGEP projects. With a total estimated capital of ~$335M, EGI's net capital investment is ~$121M (these metrics include 2 economic development projects). The approved projects for community expansion Phase 2 have a mandated requirement for execution start (shovels in the ground) by 2025 at the latest. See **Figure 5.1-6** for the approved project locations.

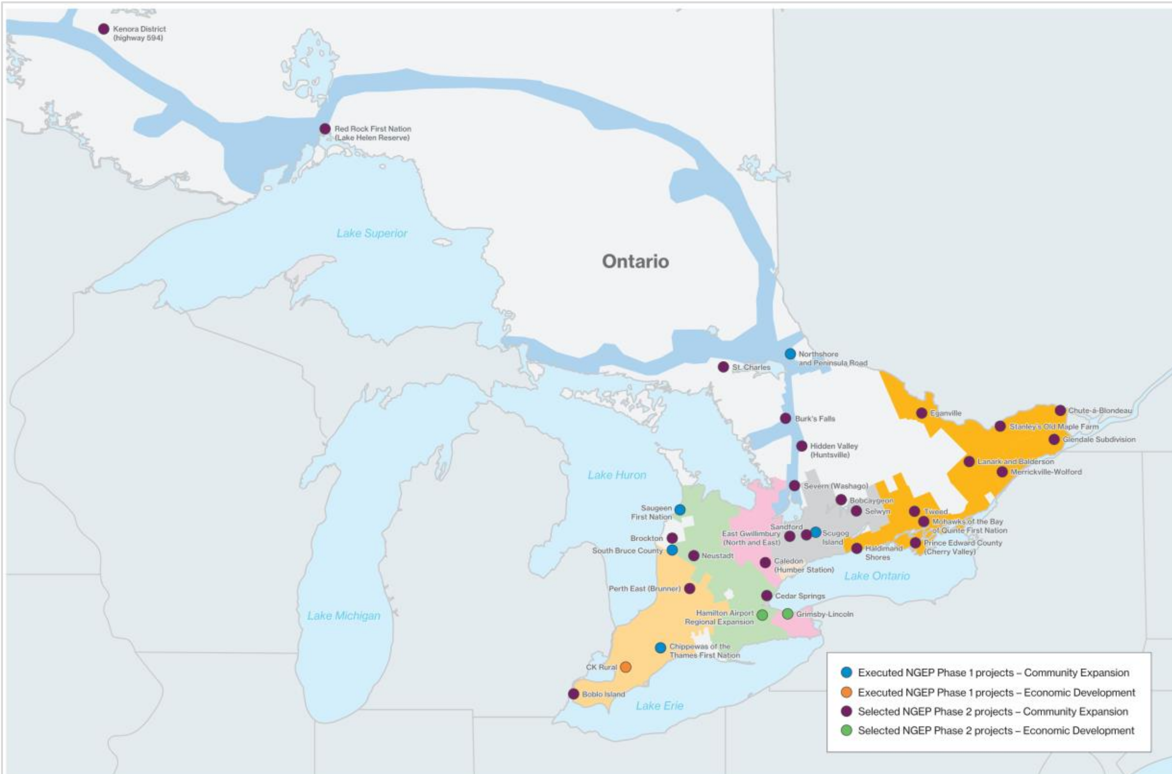


Figure 5.1-6: Approved Community Expansion Project Locations – Phase 1 and 2 Approved Projects (including Community Expansion and Economic Development)

5.1.6.1 Risk and Opportunities

Community expansion is a key business activity that helps grow and sustain EGI's core business and provides economic benefits to those served. As a result, there are a number of risks EGI would experience if community expansion activities are not pursued, including the potential loss of investment opportunities, potential franchise bypass, and the potential negative impact to EGI's brand and reputation.

Executing the program offers many opportunities including delivering on the commitment to the Government of Ontario and expanding EGI's asset footprint, promoting natural gas as an alternative energy source for rural, northern and Indigenous communities, enhancing relationships with local communities and government, and ensuring EGI maintains a competitive approach to acquiring new business, maintaining the EGI franchise area.

The Community Expansion Program offers continued opportunity through potential future phases of the government program. Application opportunities for project funding are dictated by the government under *Bill 32: Access to Natural Gas Act, 2018* and are released in phases with a maximum funding potential. EGI will continue assessing and pursuing opportunities to provide gas distribution service to under-served communities. The process will require submissions to the OEB for approval of funding awarded by the MENDM as well as the subsequent submissions of Leave to Construct (LTC) applications to the OEB for the awarded projects, as applicable. With changing government, future phases of this program may evolve over time and or be revoked which is a risk that could arise for the longevity of the program.

5.1.7 Transmission System Reinforcement

In addition to distribution system 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 (see **Section 5.3.6**).

5.1.7.1 Transmission System Forecasting 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 distribution systems.

EGI will periodically conduct new or existing capacity open seasons to gauge market demand for transportation services. In addition, EGI conducts reverse open seasons to ensure that the existing assets are maximized before contemplating new growth expansion. Transmission systems are designed to meet capacity on a design day demand to ensure all firm customer demand can be reliably served on the design day. Metered data is gathered and analyzed each year to calculate demand assumptions used for system design.

To identify purpose, need and timing of transmission system reinforcements, EGI annually completes a design day demand forecast that is used to identify short- and long-range plans through model simulation. In addition, EGI uses the IRP assessment process to binary screen the identified needs; and for those that pass the binary screening, a technical and economic evaluation of IRPAs is completed (see **Appendix B – IRP**).

5.1.7.2 Transmission System Forecast

Shippers continue to want access to the Dawn Hub and with potential further reductions in North American coal consumption, the flow of natural gas on the Canadian and U.S. pipeline grid is changing and continuing to evolve.

The Dawn Hub attracts a diversified supply mix from most major natural gas producing regions including the Western Canadian Sedimentary Basin (WCSB) and Marcellus and Utica basins as Dawn remains one of the most active natural gas trading hubs in North America. Dawn storage continues to provide security of supply and price stability for Ontario including during times of supply constraint.

EGI determines the need, timing, location and scope for system reinforcement. Transmission system reinforcements 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.

No storage growth is forecast for the regulated asset base at this time. Based on the most recent demand forecast, EGI is forecasting the need for incremental capacity requirements on the Dawn Parkway system by November 1, 2026. As stated above, EGI will confirm Dawn Parkway system demand approaching the forecast time of need by completing an open season and a reverse open season for capacity turnback. As part of the planning process, EGI will evaluate facility and non-facility alternatives to determine the most reliable and cost-effective way to deliver firm supply to meet customer demand.

EGI anticipates further growth on the Panhandle Transmission system supporting new demand from the greenhouse sector based on the latest expression of interest completed in 2021.

5.1.7.3 Risk and Opportunity

The risks identified for transmission reinforcements are operational and financial risks. While the probability of occurrence is low for the aforementioned risks, 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, and 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 5.2.3.3**). If reinforcements are not completed as required, there is a risk of supply shortfalls (both in- and ex-franchise) on design day. 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 litigation if contract or service commitments are not met and potential lost revenues.

5.1.8 Hydrogen Blending

Enbridge intends to adapt to the energy transition over time to achieve net zero scope 1 and 2 emissions by 2050 and reduce the emissions intensity of EGI's operations 35% by 2030 (2018 baseline) while continuing to provide the energy people need. Through hydrogen feasibility studies and pilot projects, EGI continues to mature and apply learnings to ensure operations can be safely adapted to a hydrogen-based economy while simultaneously meeting both EGI's goal of net-zero emissions and realizing the commitments Canada has made to reduce Greenhouse Gas (GHG) emissions. Many effective energy transition initiatives will be required to meet EGI's future emission goals and hydrogen is a key initiative towards this goal. Exhibit 4, Tab 2, Schedule 6 provides detail on EGI's Hydrogen Strategy.

EGI is a North American leader in hydrogen with the launch of EGI's hydrogen blending facility in Markham, Ontario. This pilot project blends hydrogen into the natural gas grid and services about 3,600 homes. The emissions offset from this small pilot is a reduction of up to 119 tons of CO2e per year or the equivalent of removing 25 cars from the road. This project is one of the many strategies that EGI has executed to facilitate Ontario's transition towards a net-zero future.

EGI has categorized the hydrogen strategy and its associated investments within the growth asset class. In addition, proposed hydrogen facilities are expected to be long term assets and should be treated in alignment with other gas distribution system assets.

5.1.8.1 Risk and Opportunity

There are several factors that support hydrogen as a clean energy solution. First, by converting operations to hydrogen, EGI can meet heating requirements with a carbon neutral supply, this supports both the province's and customers' GHG reduction goals. EGI's 2024 Rate Rebasing Customer Engagement results indicate that the majority of residential and business customers are in favour EGI's plans for hydrogen gas. In addition, blending hydrogen directly into the existing natural gas network makes use of existing assets in which significant investments and expertise have been created over the past century of safe and reliable operations. Leveraging the existing infrastructure is a practical and fiscally responsible approach to reducing GHG emissions.

Government and regulatory agencies around the world including Canada are working to harmonize codes and standards for hydrogen use as an energy source. There is a great opportunity for hydrogen to become one of the key factors in reducing carbon emissions and delivering a cleaner energy. Delays in government policy to harmonize codes and standards in various jurisdictions could pose a risk to rolling out a hydrogen solution.

The use of hydrogen as a fuel source compared to natural gas is not yet an economical alternative. Additional hydrogen production scale will be required before the cost of hydrogen is competitive. As EGI expands the scope of hydrogen blending, additional renewable or low-carbon hydrogen production facilities and injection sites will be needed at a cost that is competitive for rate payers.

5.1.9 Growth and Hydrogen Strategy Outcomes

The strategies for growth and hydrogen include:

5.1.9.1 Customer Additions under EBO 188

The strategy for Customer Connections is to continue to ensure that required infrastructure is installed for the addition of all forecast customers that are feasible under *EBO 188* guidelines, in accordance with the IRP Framework, while following current forecasting practices. EGI continues to monitor and update the customer additions forecast through the annual long-range planning process, which, continues to evaluate the scope of its low-carbon strategy and the impact of energy transition on customer growth forecasts.

5.1.9.2 Distribution System Reinforcement under EBO 188

The strategy for the Distribution System Reinforcements is to continue to ensure that required infrastructure is installed to enable the addition of all forecasted customers feasible under *EBO 188* guidelines, in accordance with the IRP Framework, while following current forecasting practices. The IRP assessment process is used to evaluate whether there is an economically and technically feasible IRPA that can meet the identified system needs (see **Appendix B – IRP**).

Major distribution reinforcement projects reflected in the forecast include:

Ottawa Reinforcement Phase 2 (previously 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 TC Energy's pressure-reduced Ottawa lateral. The project involves approximately 7 km of NPS 12 pipe extending from Greenbank Road and West Hunt Club Road to Princess of Wales Drive and West Hunt Club Road. See **Appendix A, Pg. 22** for additional detail on this investment.

East Kingston Creekford Road Reinforcement

The Kingston system is nearing capacity; flows and growth are sustainable until winter 2022/2023 (CNG will be installed for winter operations as required until project completion). Failure to implement this project could result in an inability to add customers to this system and maintain adequate system pressures beyond 2024. See **Appendix A, Pg. 24** for additional detail on this investment.

Hamilton Industrial Reinforcement

This reinforcement project supports changes to industrial demand in the area. See **Appendix A, Pg. 23** for additional detail on this investment.

North Parry Sound Seguin Trail Reinforcement

This reinforcement project supports the growth of the Parry Sound system. Failure to implement this project could result in an inability to add customers to this system and maintain adequate system pressures beyond 2032. See **Appendix A, Pg. 25** for additional detail on this investment.

Southeast Owen Sound County Road 40 Reinforcement

System reinforcement is required to support the growth on the Owen Sound system north of St. Jacobs in 2025. See **Appendix A, Pg. 26** for additional detail on this investment.

Wheatley 1B Panhandle Distribution Reinforcement - Wheatley Lateral Replacement and Reinforcement

Greenhouse growth in the Windsor area continues. The Panhandle distribution network requires reinforcement to allow for the continued industrial customer expansion. The Panhandle Transmission System Reinforcement (see **Section 5.1.9.4**) is also required to meet the demand of the region. Wheatley-1B is a distribution system looping project which requires a new station at Wheatley Rd. and Goodreau Line to include 5,300 m of NPS 8 and 10,800 m of NPS 8. See **Appendix A, Pg. 27** for additional detail on this investment.

5.1.9.3 Community Expansion

The strategy for Community Expansion is to execute the required infrastructure on all projects that were awarded funding under *Bill 32.* All Phase 2 projects must begin execution before the end of 2025 which has been built into the long-range plan. **Table 5.1.9-1** identifies the large Community Expansion projects reflected in the forecast. Capital expenditure associated with Community Expansion projects is not included in the AMP's capital expenditure (see Phase 2 of the Natural Gas Expansion Program (ERO 019-3191).

Table 5.1.9-1: Major Community Expansion Projects

EGI Community Expansion Projects	Operations Region	Rate Zone(s)	Pipe Length (km)	Pipe Diameter	Forecast (NET BASE CAPEX)
Bobcaygeon	GTA East	EGD	77.5	1.25 to 6 PE & ST, NPS 6 ST, NPS 8 ST (9.5 km)	$47.5M
Eganville	Eastern	EGD	59.4	4 ST (1.2 km), 8 PE, 6 PE, 4 PE, 2 PE	$10.6M
Washago	Northern	Union	51	6 PE, 4 PE, 2 PE	$9.7M
Lanark and Balderson	Eastern	EGD	36	6 PE, 4 PE, 2 PE	$6.5M
North and East (East Gwillimbury)	GTA East	EGD	30.2	2 PE, 4 PE	$7.2M

5.1.9.4 Transmission System Reinforcement System Growth under EBO 134

The strategy for the Transmission System Reinforcements is to continue to ensure that required infrastructure is installed to enable the addition of all forecasted customers and distribution growth feasible under *EBO 134* guidelines, while following current forecasting practices. The IRP assessment process is used to evaluate whether there is an economically and technically feasible IRPA that can meet the identified system needs (see **Appendix B – IRP**). Due to the Copperleaf classification, the capital expenditure related to Transmission System Growth Investments is captured under the Transmission Pipe and Underground Storage capital expenditure summary (see **Section 5.3.6.4**).

The following major transmission reinforcement projects are reflected in the forecast:

Dawn to Parkway - Kirkwall to Hamilton Expansion

The Dawn Parkway - Kirkwall to Hamilton Expansion is required to provide reliable, secure, economic natural gas capacity to meet the growing design day demand of the Dawn Parkway Transmission system which serves both in- and ex-franchise markets. The Kirkwall-Hamilton Expansion Project consists of 10.2 km of NPS 48 pipeline from the Kirkwall Valve Site to the Hamilton Valve Site. The project is estimated to provide 72.4 TJ/d of incremental capacity to the Dawn Parkway Transmission System and is required to be in service in 2026. See **Appendix A, Pg. 58** for additional detail on this investment.

Dawn Parkway Expansion Project - Dawn-Enniskillen

Based on the current demand forecast, EGI has determined that the next Dawn Parkway System facilities will need to be in place as early as the 2029 to 2030 winter season (construction beginning in 2029). These facilities are incremental to the Kirkwall to Hamilton Expansion and timing is dependent on the Dawn Parkway System demands. See **Appendix A, Pg. 57** for additional detail on this investment.

Panhandle Transmission System Reinforcement

In response to increasing natural gas demand growth in the areas served by EGI's Panhandle Transmission System ("Panhandle System"), EGI is proposing to construct the following facilities, collectively referred to as the Panhandle Regional Expansion Project. See **Appendix A, Pg. 60** for additional detail on this investment.

Panhandle Regional Expansion Project - Leamington Interconnect

Approximately 12 km of NPS 16 natural gas pipeline with a MOP of 6,040 kPa will be installed in the Municipality of Lakeshore, the Town of Kingsville, and the Municipality of Leamington with a 2024 in-service date. See **Appendix A, Pg. 62** for additional detail on this investment.

Panhandle Regional Expansion Project - NPS 36 looping to Comber Transmission

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 as early as the 2028 winter season. These facilities are incremental to the Panhandle Regional Expansion Project and timing is dependent on the Panhandle System demands. See **Appendix A, Pg. 64** for additional detail on this investment.

5.1.9.5 Hydrogen Strategy

EGI plans to apply learnings from its Hydrogen Blending pilot projects and its hydrogen blending facility in Markham to allow it to further Canadian leadership on hydrogen development and a low-carbon future. EGI continues to collaborate with governments and partners to advance innovative energy solutions to keep energy reliable and affordable while reducing environmental impact.

EGI continues to evaluate the extent that hydrogen can be used in the distribution system and company assets, the following projects and feasibility studies are planned for 2023 to 2032:

- **Hydrogen Blending Phase 2:** Phase 2 of the Markham Hydrogen Blending pilot project includes adding an additional 12,400 customers (approximate).
- **Hydrogen Studies:** As hydrogen technology is relatively new within the natural gas distribution industry, these studies are required to allow EGI to identify and prioritize the sections of the gas grid and equipment most suitable for hydrogen blending and to evaluate any required upgrades. See **Appendix A, Pg. 28** for additional detail.

5.1.10 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. The total average capital spend is forecast to be $295M (EGI) as summarized in **Table 5.1.10-1**. Growth capital is further summarized as part of EGI's total 10-year capital plan in **Section 6**. See **Appendix B – IRP** for the status of the outcomes of the IRP assessment process, including the binary screen and the status evaluation of IRPAs.

Note: The Community Expansion investments are not included in the capital summaries of this AMP. Capital costs related to transmission system reinforcements are included in the expenditure summary for the Transmission Pipe and Underground Storage asset class (see **Section 5.3.6.4**).

Table 5.1.10-1: Growth Capital Summary ($ Millions) - EGI[6]

Asset Class Strategy/Investment Name	Asset Program	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-Year Forecast
Customer Additions under EBO 188[7]	Customer Connections	220.4M	249.2M	249.2M	250.3M	260.6M	250.1M	242.8M	246.7M	240.2M	229.6M	**2439.0M**
Hydrogen Strategy	Hydrogen Blending	2.1M	3.8M	5.2M	2.0M	-	-	-	-	-	-	**13.0M**
Enbridge Gas Distribution System Hydrogen Feasibility Study		-	5.1M	5.2M	5.2M	-	-	-	-	-	-	**15.5M**
Distribution System Reinforcement under EBO 188	System Reinforcement	44.5M	41.9M	14.9M	27.1M	8.3M	10.3M	3.4M	10.9M	13.9M	9.2M	**184.5M**
Rideau Reinforcement		-	-	-	-	-	-	-	0.4M	7.5M	63.7M	**71.6M**
Hamilton Industrial Reinforcement		2.5M	10.3M	113.6M	6.5M	-	-	-	-	-	-	**132.9M**
East Kingston Creekford Road Reinforcement		4.6M	24.1M	-	-	-	-	-	-	-	-	**28.7M**
North Parry Sound Seguin Trail Reinforcement		-	-	-	-	-	-	-	-	-	23.8M	**23.8M**
Southeast Owen Sound County Rd 40 Reinforcement		-	-	34.1M	-	-	-	-	-	-	-	**34.1M**

[6] Includes overhead allocation
[7] The 10-Year Forecast for Customer Connections was informed by the 2022 LRP

Asset Class Strategy/Investment Name	Asset Program	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-Year Forecast
Wheatley 1B Panhandle Distribution Reinforcement - Wheatley Lateral Replacement and Reinforcement		1.2M	19.9M	-	-	-	-	-	-	-	-	**21.1M**
Total		**275.3M**	**354.3M**	**422.1M**	**291.1M**	**268.9M**	**260.4M**	**246.2M**	**258.0M**	**261.6M**	**326.3M**	**2964.2M**

5.2 Distribution Operations

EGI's distribution operations provide safe, affordable, reliable energy to about 3.8 million homes, businesses and industries and serves about 75% of Ontario residents. The distribution operations asset classes consist of a network of natural gas assets that take gas from the higher-pressure transmission system and distribute it to residential, commercial and industrial customers. This is achieved through a series of pipelines of various operating pressures, regulation stations 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.

EGI's distribution assets are categorized in the following asset classes:

- Distribution Pipe
- Distribution Stations
- Utilization

Distribution Stations are 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 overpressure protection to the lower-pressure system. Distribution Stations include all natural gas entry points into the EGI distribution network, control points throughout the network and delivery points to end-use customers. Depending on the facility, additional purposes may include gas metering, odourization and monitoring.

Once regulated to distribution pressures, natural gas is transported through the Distribution Pipe network. Distribution Pipe includes pipe, valves, all pipe appurtenances, services and risers installed up to Utilization assets.

Utilization assets are the components of the distribution system that regulate system pressure, ensure low pressure delivery to the customer and measure gas consumption, these assets support the delivery of gas primarily to customers consuming volumes less than 17.0 m³/h at a typical pressure of 7" wc, Utilization assets typically begin at the service shut-off valve. **Figure 5.2-1** shows EGI's distribution operations system service maps.

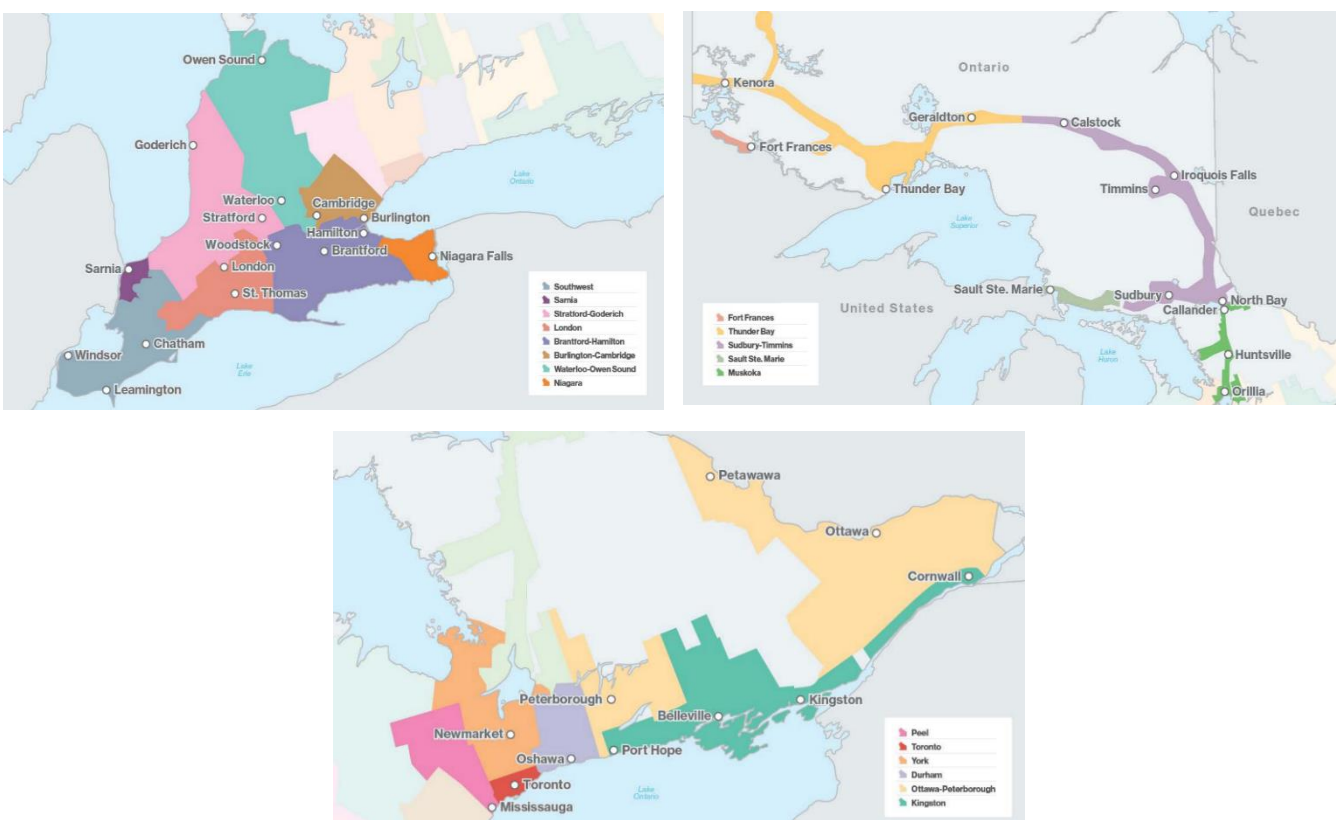


Figure 5.2-1: Distribution Operations System Service Maps

5.2.1 Distribution Operations Objectives

The objectives of Distribution Operations are shown in **Table 5.2.1-1**.

Table 5.2.1-1: Distribution Operations Objectives

Applicable Asset Class	Asset Class Objective	Description
Distribution Pipe **Distribution Stations** **Utilization**	**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.
		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.
Distribution Pipe **Distribution Stations**	**Integrated Resource Planning**	Screen projects using EGI's IRP Assessment Process; for those that pass, determine if there are IRPAs that are economically and technically feasible.
Distribution Pipe	**Relocations**	Relocate pipe assets to reduce or mitigate the impact of planned third-party work to ensure the safe and reliable operation of the distribution system.
		Recover costs allowed by municipal franchises and other agreements for relocations initiated by third parties.

5.2.1.1 Performance Measures

The performance measures for the Distribution Operations asset classes are shown in **Table 5.2.1-2**.

Table 5.2.1-2: Distribution Operations Performance Measures

Asset Class	Performance Measure
Distribution Pipe	• Percentage of leaks reported by leak survey (vs. leaks reported by the public) • Leaks per 1,000 km • Number of immediate digs per 100 km • Number of scheduled digs per 100 km • Bare and unprotected steel systems (km) • Steel Mains (Pre- and including 1970) pipeline systems (km)
Distribution Stations	• Composite Compliance – Delivery to Plan • Stations Inspections • Work Orders Percentage Complete
Utilization	• Completion of Government Inspection Meter Exchange (MXGI) Program • Number of aboveground leaks • Number of non-program failures and explanations

To achieve the asset class objectives listed in **Table 5.2.1-1**, asset investment decisions are governed by the life-cycle management strategies outlined in **Table 4.1-1**.

5.2.2 Distribution Operations Asset Class Hierarchy

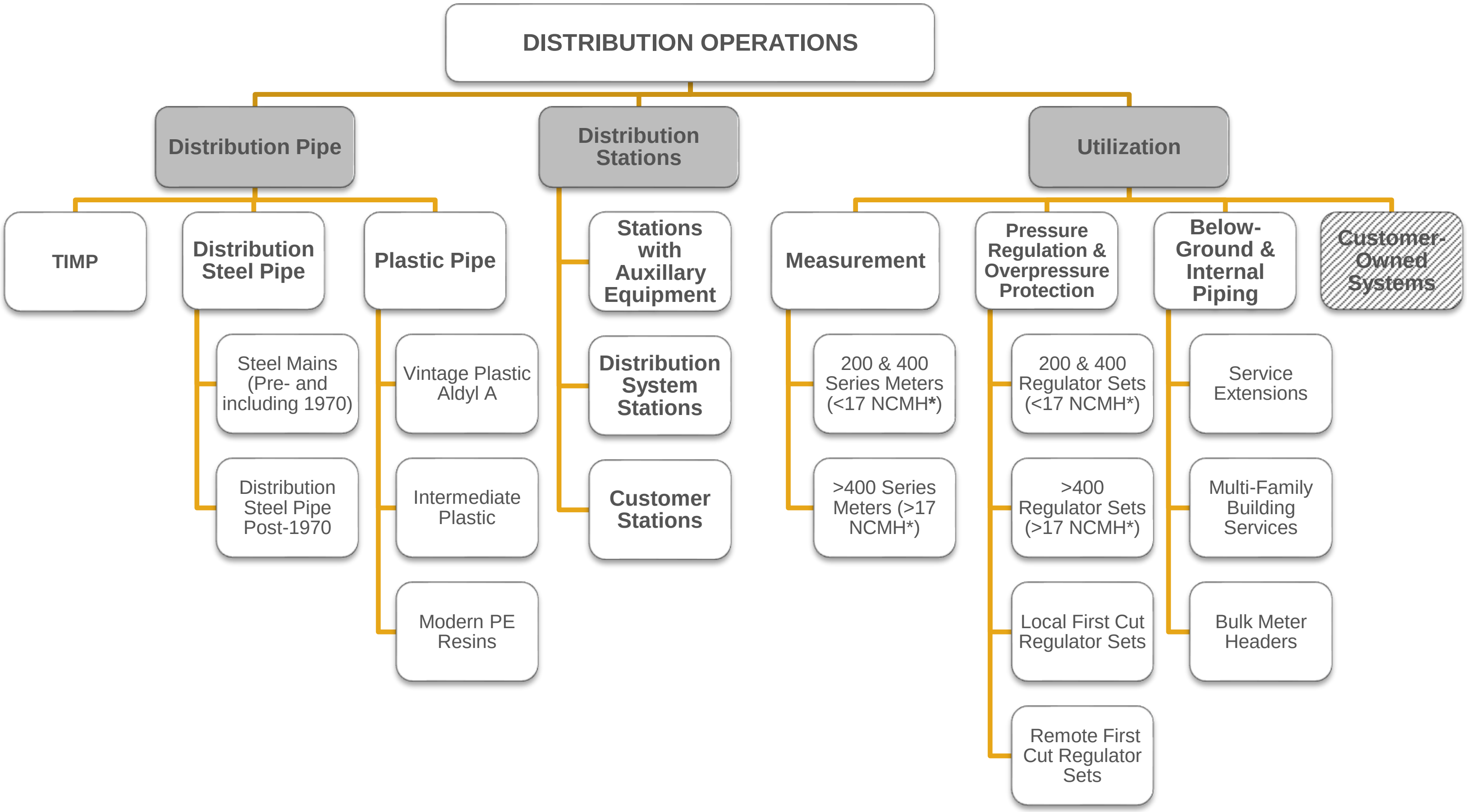


Figure 5.2-2: Distribution Operations Asset Class Hierarchy

Notes:

- Some Pipe asset subclasses (e.g., Distribution Steel Pipe Pre-1970) have programs that apply to only a portion of the assets (e.g., bare and unprotected steel).
- The Transmission Integrity Management Program (TIMP) 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 nondestructive 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 Distribution Pipe asset class.
- Customer-owned systems are included for illustrative purposes only.
- *Normal Cubic Metres per Hour

5.2.3 Distribution 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 of a transmission system.

Pipe includes pipe, valves, all pipe appurtenances, service lines and risers installed up to Utilization components (typically, assets belonging to the Utilization asset class [see **Section 5.2.5**] begin at the service shutoff valve). Distribution piping can be located inside or outside of a building.

5.2.3.1 Distribution Pipe Inventory

Table 5.2.3-1 lists the inventory details for each asset subclass, along with selected other component inventories relevant to certain programs.

Table 5.2.3-1: Distribution Pipe Inventory[8]

Asset	EGD Rate Zone	Union Rate Zones
Mains (km)	**42,973**	**44,690**
TIMP Pipe - Distribution Pipe	341	1,744
TIMP Pipe - Transmission Pipe*	142	1,312
Steel Mains (Pre- and including 1970)	7,292	10,131
Distribution Steel Pipe Post-1970	6,593	8,788
Plastic Pipe - Modern PE	22,763	12,372
Plastic Pipe - Intermediate Plastic Mains	4,721	1,342
Plastic Pipe - Not yet categorized	N/A	7,893
Plastic Pipe - Vintage Plastic Aldyl A	1,042	1,053
Select additional asset inventories		
Bare unprotected pipe (km) **	0	136
Copper Services (#)	2,006	0
Copper Risers (#)	257,712	0

**TIMP Pipe includes assets that are part of the Transmission Pipe and Underground Storage asset class and the Distribution Pipe asset class. Transmission Pipe is shown here as well for clarity as it is discussed in following subsections.*

***Bare unprotected pipe is a subset of Steel Mains (Pre- and including 1970).*

[8] Inventory as of December 2021.

5.2.3.2 Pipe Condition and Strategy Overview

Table 5.2.3-2: 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 pipelines are generally believed to be in generally good condition with respect to failures caused by corrosion or other geometric anomalies, the risk for which is monitored through various condition monitoring techniques such as in-line inspections (ILI) and external corrosion direct assessment (ECDA). Actionable features from these activities are then prioritized for direct examination via the Integrity Dig Program. As technologies which support these inspections improve, EGI continues to identify and assess new anomalies which require remedial action to maintain risk levels within a tolerable region. Additionally, as EGI continues to enhance its hazard assessment and maintenance programs, additional hazards such as geohazards and long seam anomalies will be assessed and managed as they are identified.	Risks identified for TIMP pipe: **Employee and Contractor Health and Safety Risk / Public Health and Safety Risk**: Gas pipelines operating above 30% SMYS can rupture, leading to explosion. For lower stress pipelines, gas leaks would be the preeminent failure mode. **Financial Risk**: Total repair costs, commodity loss, relighting customer gas appliances, regulatory penalties and any property damages caused by loss of containment, penalties due to inability to meet contractual obligations **Operational Risk**: 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 Condition Monitoring Operating Standard • 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 Operating Standard • Easement Control Operating Standard including easement encroachment and easement clearing • Geohazard baseline reports	The replacement/renewal strategy for TIMP pipe includes: • Inspection Program Integrity Retrofits and Digs • Alternative condition verification methods such as hydrostatic testing. • Class Location Program • Depth of Cover Program • MOP Verification Program • Replacement of pipelines or pipeline segments as required based on condition and risk assessment findings
Steel Mains (Pre- and including 1970)	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. Identifiable condition of these assets is determined through maintenance programs, condition assessment programs, tacit knowledge (subject matter advisor [SMA] / worker input) and reliability modelling.	Risks identified for Distribution Steel and Plastic pipe: **Employee and Contractor Health and Safety Risk / 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**: Greenhouse gas (GHG) emissions, environmental impact, service interruptions and reputational damages **Environmental Risk**: 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, cathodic protection (CP) 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) • Distribution Integrity Management Program (DIMP) Asset Health Review operating process • Condition assessment programs including integrity assessments and Quality Material Equipment Reports (QMER) 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 • Proactive Vintage Steel Pipe Replacement Program • General Replacement Program • Emergency Replacement Program • Major discrete replacement project work • Corrosion Prevention Program • Continuous Improvement of reliability models and asset understanding • 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 Quality Material Equipment Reports (QMER) to identify and assess failure mechanisms of assets	The replacement/renewal strategies to manage distribution plastic pipe include: • AMP-Fitting Replacement Program • Reactive Vintage Plastic Aldyl A Replacement • Service Replacement Program • Emergency Replacement Program • General Replacement Program • Relocation Program (externally driven) • Continuous Improvement of reliability models and asset understanding
Distribution Plastic Mains Intermediate Plastic Mains	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 and will be monitored through EGI processes. Replacements/repairs will take place as required.			

5.2.3.3 TIMP Mains

EGI has implemented an Integrity Management Program (IMP) pursuant to Technical Standards & 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 other periodic condition monitoring techniques 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 the Transmission 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 341 and 1,744 km of steel pipe for the legacy Enbridge Gas Distribution (EGD) and legacy Union Gas (Union) rate zones respectively, for a combined length of 2,085 km.

The population of TIMP pipe in the Storage and Transmission Operations TIMP portfolio consists of approximately 142 and 1,312 km of steel pipe for the EGD and Union rate zones respectively, for a combined length of 1,454 km.

Despite increasing age, TIMP pipelines are generally in good condition with low failure susceptibility to monitored hazards. The population of TIMP pipelines by decade of installation is shown in **Figure 5.2-3**, illustrating a wide distribution of age for this group of assets. Based on length, over 40% of TIMP pipelines were installed prior to 1970. To ensure continued safe and reliable operation and in response to failures experienced by other pipeline operators, EGI has introduced enhanced hazard susceptibility assessments to ensure TIMP assets remain fit for service. To achieve the appropriate levels of safety and reliability, EGI will expand the ILI Program to include more pipelines, introduce additional condition monitoring methods, and will retrofit select pipelines where advances in ILI technology enable newly identified or emerging hazards to be detected. Where condition monitoring methods are operationally inviable or more costly than renewal, some assets may be renewed in lieu of inspection.

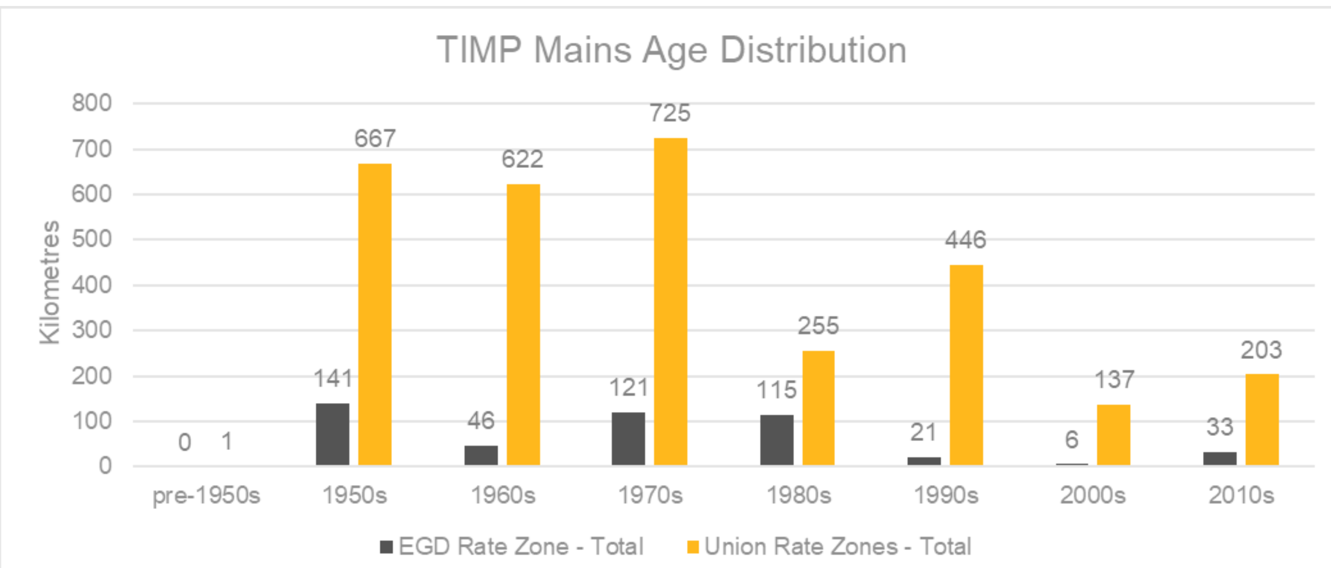


Figure 5.2-3: TIMP Pipelines Age Distribution

5.2.3.3.1 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 approach 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. Hazard mechanisms are understood, and risks are assessed through data analytics that establish the likelihood and consequence of various types of failures. This facilitates pipeline integrity management activities and optimizes the use of resources to control risk. Hazards assessed include:

- External corrosion
- Internal corrosion
- Internal erosion
- Manufacturing-related defects
- Welding/fabrication-related defects
- Equipment failure
- Third-party/mechanical damage
- Stress-corrosion cracking
- Outside forces
- Weather-related hazards
- Incorrect operations
- Cold-weld weakening bond line defects

As hazards are identified on pipelines, appropriate methods of preventing and detecting hazards 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. The majority of 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 (i.e., digs) and inspection using nondestructive examination (NDE) 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 spotting and remediating detectable pipeline hazards. There are, however, some hazards that are undetectable by modern integrity inspection techniques, including some long seam anomalies. Progression of such defects cannot be practically monitored using current in-line inspection and external corrosion direct assessment (ECDA). Therefore, alternative condition verification methods such as hydrostatic testing are considered and compared to an option to replace such pipelines based on inherent risk and cost benefits associated with each option.

TIMP pipelines are also subject to depth of cover surveys and class location surveys as part of the TIMP Mains Strategies (see **Section 5.2.3.6.1**). Any changes in class location or depth of cover are assessed to determine if mitigations are required.

5.2.3.3.2 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 inspected assets is generally well understood. Integrity activities on these pipelines typically result from the investigation of time-dependent events (such as corrosion) and time-independent events (such as third-party damage).

In the TIMP, EGI uses ILI data analysis and risk assessment of pipeline features along with corrosion growth modelling to project known detectable 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 ILI is introduced for more 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 six-year period is shown in **Figure 5.2-4**.

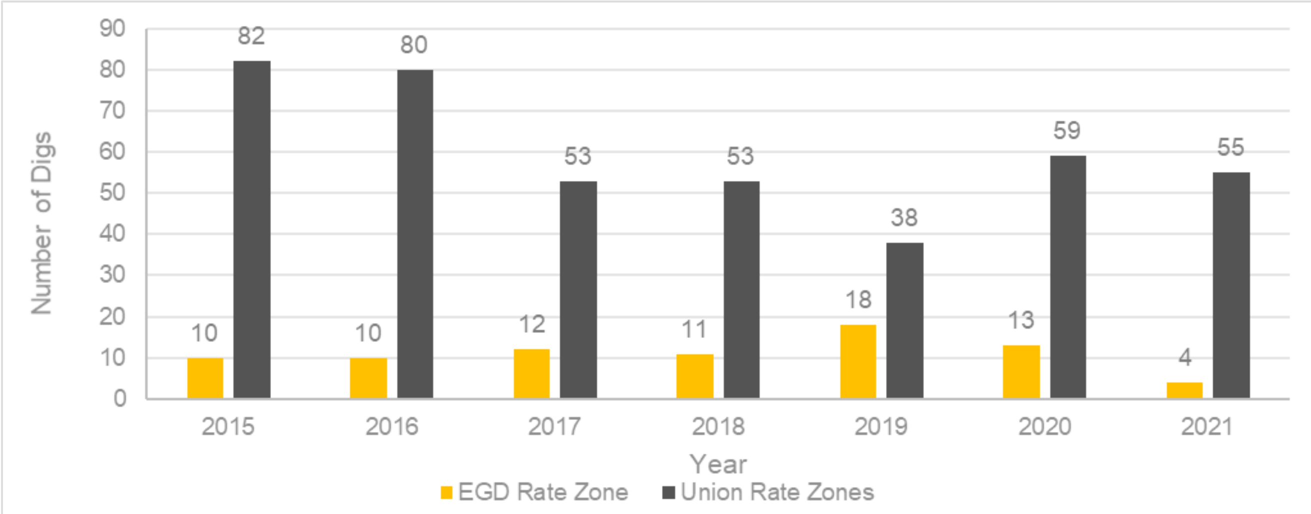


Figure 5.2-4: EGI Historical Digs

In addition to the identification of hazards through in-line inspection, EGI has also successfully identified and remediated pipeline sections with low depth of cover and exposed watercourse crossings through previously listed maintenance strategies. EGI will continue to monitor changing conditions around its pipelines and ensure such hazards are sufficiently managed.

5.2.3.3.3 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, inform models 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. Where pipeline defects cannot be identified and monitored by modern inspection techniques, alternative condition verification methods such as hydrostatic testing are considered and compared to an option to replace such pipelines based on operational viability and inherent risk and cost benefits associated with each option.

5.2.3.4 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 13,884 and 18,918 km of steel pipe for the EGD and Union rate zones respectively, for a combined steel pipe network of 32,802 km. This population is further subdivided into two asset subclasses, Steel Mains (Pre- and including 1970) 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. **Figure 5.2-5** and **Figure 5.2-6** illustrate the calendar age of the steel main population for the EGD and Union rate zones respectively.

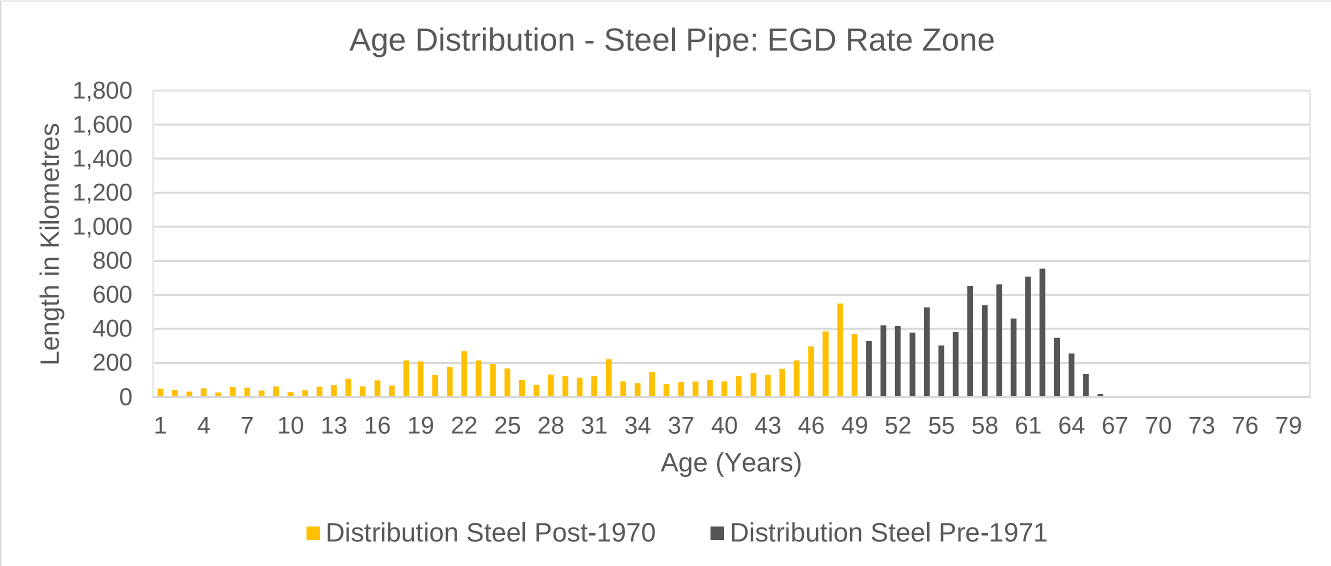


Figure 5.2-5: Age Distribution - Steel Pipe: EGD Rate Zone

In **Figure 5.2-6,** the population spike in 1958 (at age 62) is due to rapid expansion and acquisitions made by Union (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.

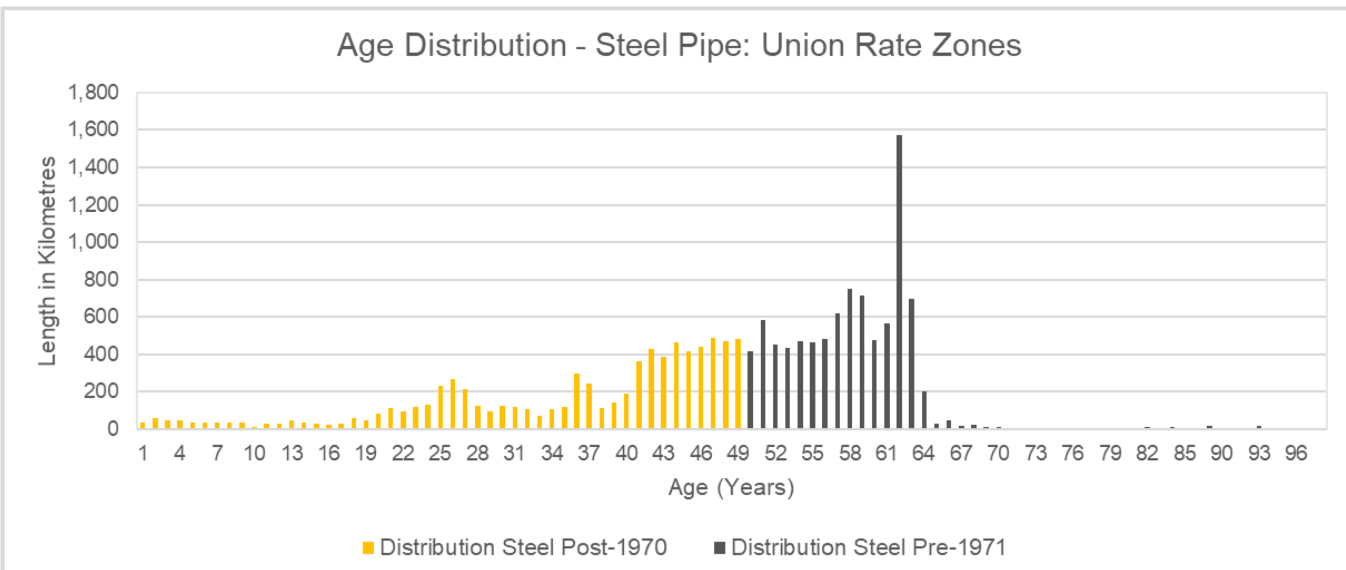


Figure 5.2-6: Age Distribution - Steel Pipe: Union Rate Zones

5.2.3.4.1 STEEL MAINS (PRE- AND INCLUDING 1970)

The Steel Mains (Pre- and including 1970) 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 7,292 and 10,131 km of pipe for the EGD and Union rate zones respectively, totaling 17,423 km). These mains were installed using materials, 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.

5.2.3.4.1.1 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 Quality Material Equipment Reports (QMER) identify and assess the failure mechanisms of EGI's assets.
- **Tacit knowledge (subject matter advisors [SMAs] / worker input):** Field knowledge is used to identify potential condition issues through regular meetings with SMAs.
- **Reliability modelling:** One of the major hazards to steel mains is corrosion. A reliability model accounting for pipe attributes has been developed through the Asset Health Review (AHR) operating process under DIMP to forecast the number of corrosion leaks based on statistical analysis of corrosion leak history (including factors that accelerate degradation).

5.2.3.4.1.2 Condition Findings

5.2.3.4.1.2.1 Steel Mains

Based on the condition assessment methodologies outlined in the previous section, **Table 5.2.3-3** outlines the condition findings generally associated with assets in the Steel Mains (Pre- and including 1970) asset subclass.

Table 5.2.3-3: Condition Findings for Steel Mains (Pre- and including 1970)

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. Bare and unprotected failures (see **Figure 5.2-7**) are corrosion-driven and directly tied to lack of coating and cathodic protection.
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 5.2-9**).
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.
Compression Couplings: Corrosion	Compression couplings on steel mains can be susceptible to external corrosion and lead to an increased risk of leaks.
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.

Issue	Description
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 (see **Figure 5.2-10** and **Figure 5.2-11**). 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 leading to brittle-like failures. Defects in low-frequency ERW pipe welds have ruptured at operating pressures below 30% SMYS.
Geohazard	Geohazards are earth conditions that pose hazards to the public or their activities. The cause of the hazard may be natural or spurred by human activities. The following are integrity issues relating to Geohazard risks at EGI: spanning/ loss of support, deformation, overloading, and stretching/compression. These risks are accentuated by melting of ice sheets, landscape erosion by running water, landform by highly compressible organic soils, shoreline coastal erosion, and landslides, etc.
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 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 5.2-8**).
Aerial Crossings (Union)	Aerial crossings are segments of unsupported steel pipe that span water crossings and ditches. These are from legacy construction practices from the Union distribution network; and over time, the condition of these aerial crossings has degraded. Since they are aboveground pipe segments, the cathodic protection barrier is not effective, so corrosion initiation sites are able to progress unchecked (see **Figure 5.2-14**). The coatings have degraded over time as well; erosion in many locations has increased unsupported spans (see **Figure 5.2-15**). There may also be mechanical couplings present that can experience pull-outs with ground movement (see **Figure 5.2-13**). Third-party damages continue to be problematic for these exposed pipe segments.
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 (see **Figure 5.2-12**:) 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 5.2-7: Bare and unprotected steel failures

Figure 5.2-8: Shallow and embedded gas main due to road grade change

Figure 5.2-9: Severe corrosion on bridge-crossing pipe

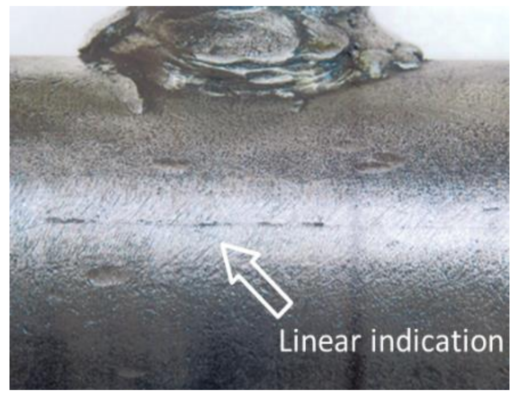


Figure 5.2-10: Vintage NPS 2 steel main with linear indication along weld seam

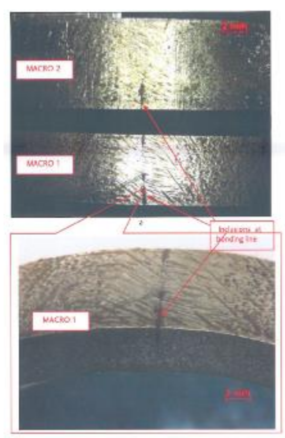


Figure 5.2-11: Inclusion at pipe weld seam on vintage NPS 2 gas main

Figure 5.2-12: Damaged drip rod on vintage NPS 2 gas main

Figure 5.2-13: Aerial crossing with exposed mechanical fitting

Figure 5.2-14: Coating degradation and corrosion pitting

Figure 5.2-15: Erosion increasing the unsupported length of an aerial crossing

Failure history for the Steel Mains (Pre- and including 1970) population is shown in **Figure 5.2-16** and **Figure 5.2-17** for the EGD and Union rate zones respectively.

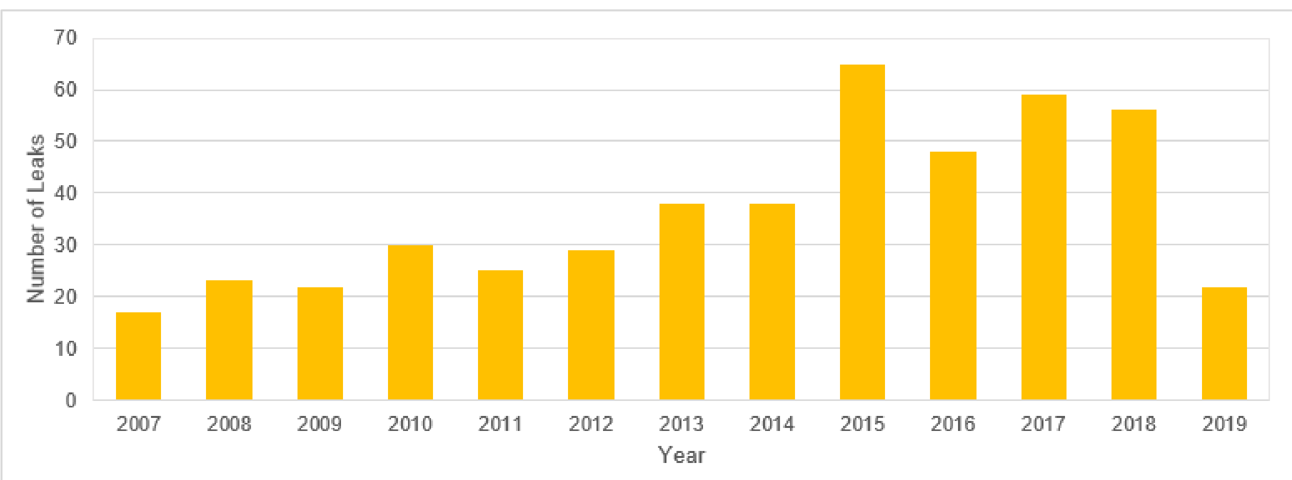


Figure 5.2-16: Corrosion Leak History: Steel Mains (Pre- and including 1970) - EGD Rate Zone

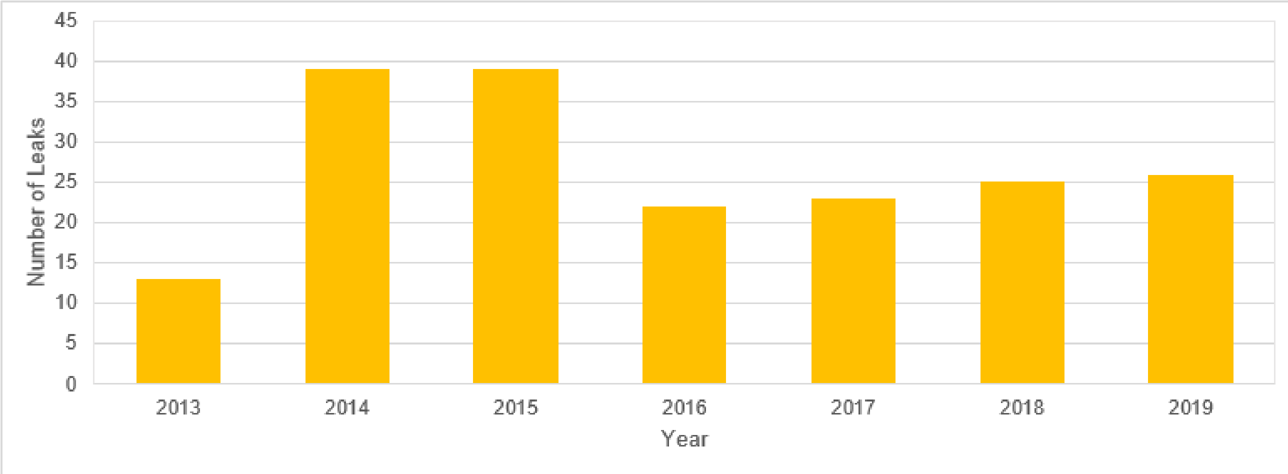


Figure 5.2-17: Corrosion Leak History: Steel Mains (Pre- and including 1970) - Union Rate Zones

The failure history is shown over the 2007 to 2019 timeframe for the EGD rate zone (see **Figure 5.2-16**) and between 2013 and 2019 for the Union rate zones (see **Figure 5.2-17**). Irregularities are most likely due to the mix of assets being leak-surveyed in a given year and the survey cycle. The survey is optimized for geography for 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 the analytics practices are aligned for reliability modelling within DIMP, the trends and predictions will evolve and become increasingly reliable.

Reliability modelling within DIMP is used to project the annual number of leaks on steel mains (pre- and including 1970) over the next 20 years (see **Figure 5.2-18** and **Figure 5.2-19**). Projections assume no change to maintenance practices (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).

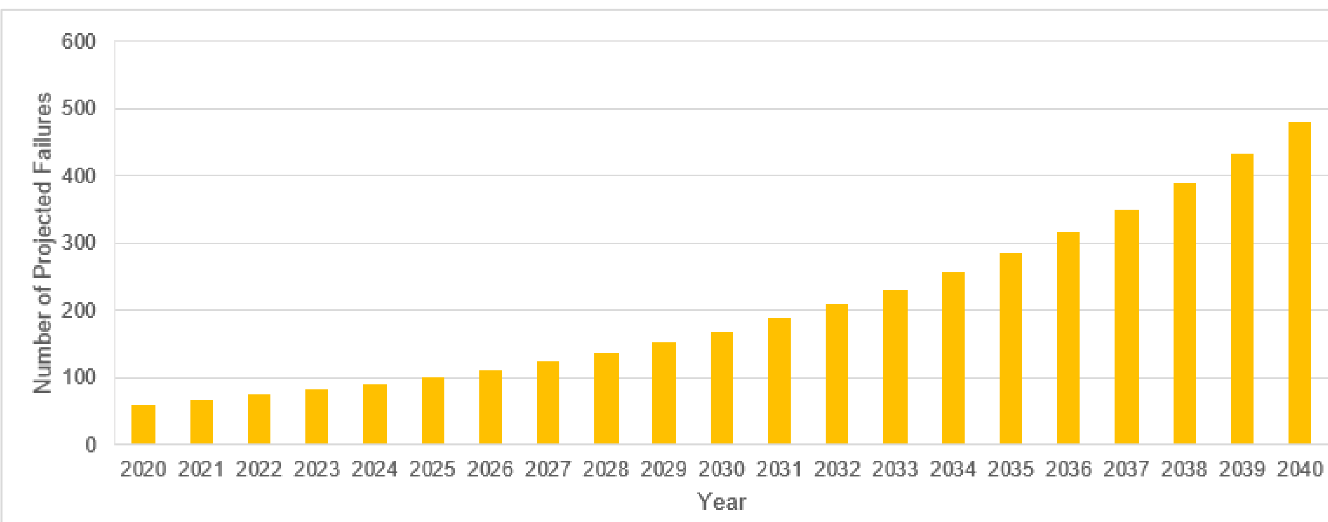


Figure 5.2-18: Corrosion Leak Projections for Steel Mains (Pre- and including 1970) - EGD Rate Zone

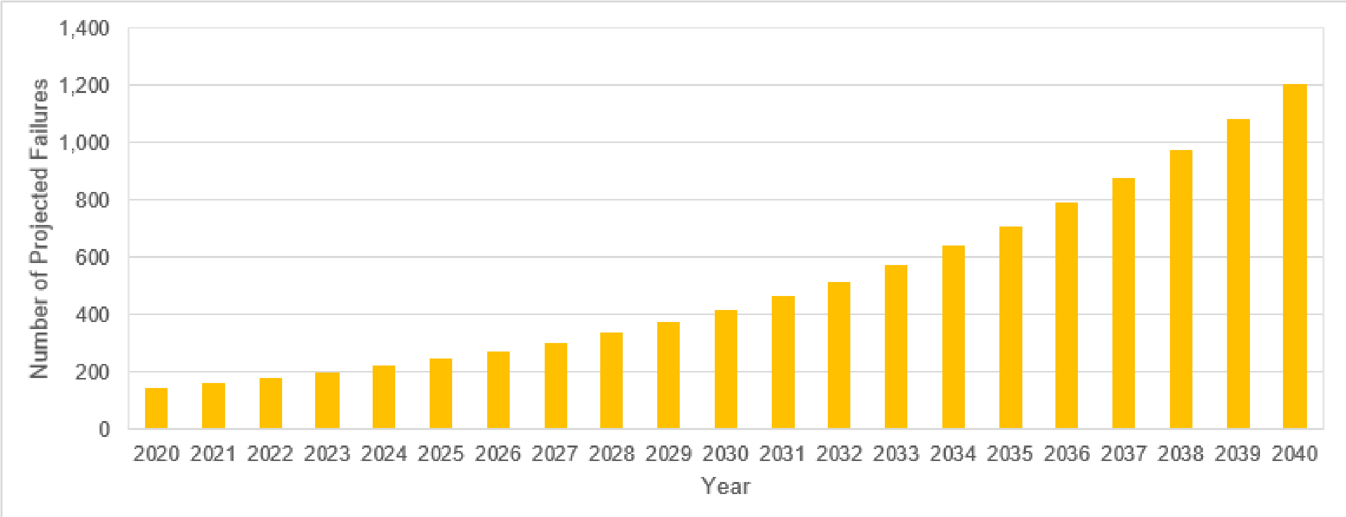


Figure 5.2-19: Corrosion Leak Projections for Steel Mains (Pre- and including 1970) - Union Rate Zones

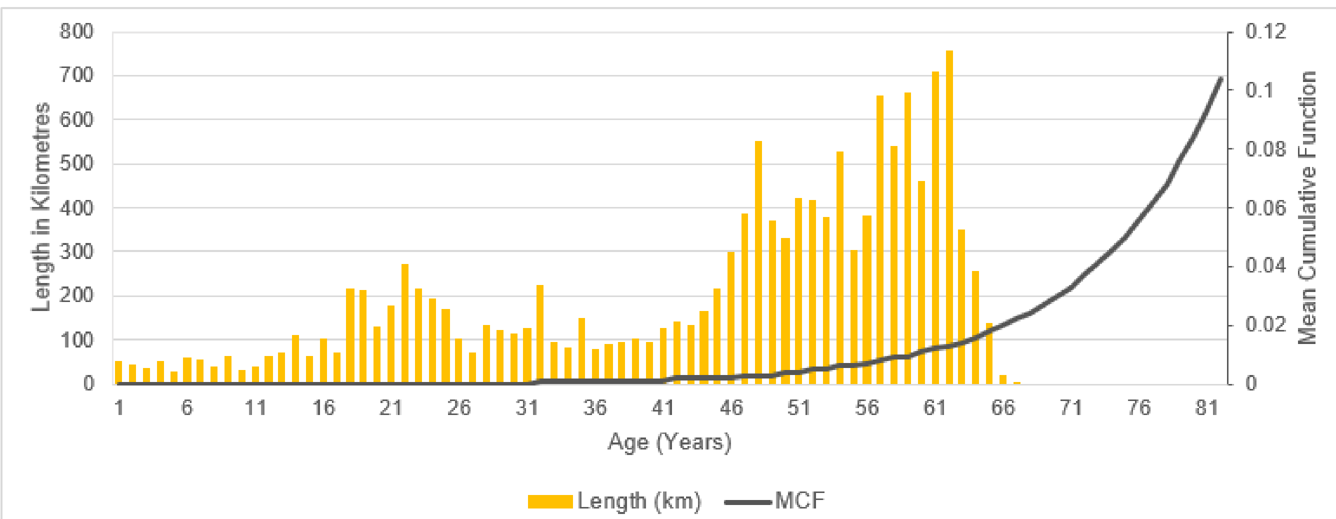


Figure 5.2-20: Steel Mains Population vs. Mean Cumulative Function for Corrosion Leaks - EGD Rate Zone

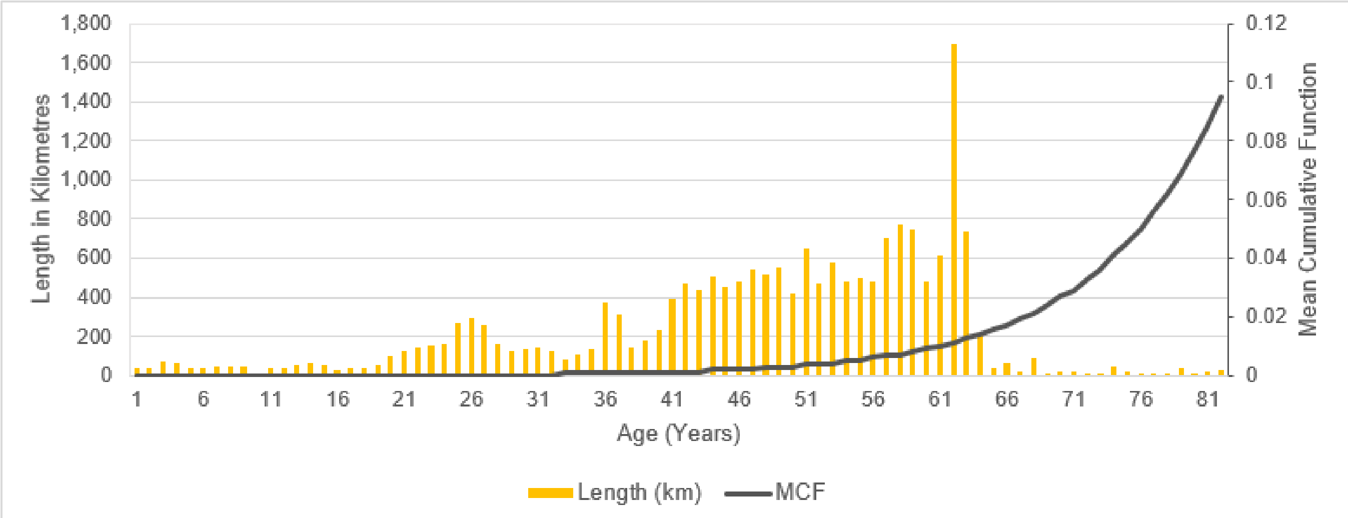


Figure 5.2-21: Steel Mains Population vs. Mean Cumulative Function for Corrosion Leaks - Union Rate Zones

The steel main reliability model forecasts the number of annual leaks will increase steadily over the next 20 years. **Figure 5.2-18** and **Figure 5.2-19** show the predicted cumulative number of corrosion-based leak failures of pipe for a given age. By 2040, the number of leaks will have increased by approximately tenfold. This represents an exponential growth in the number of leaks.

The significant increase in corrosion leaks is forecast to take place as a portion of the mains population approaches 100 years of age. This occurs between 2037 and 2057. **Figure 5.2-20** and **Figure 5.2-21** show a sharp increase in failures that could be due to multiple coating defects along the pipe body and/or poor cathodic protection history. Coating defects can result from manufacturing defects, field-applied coating anomalies, coating degradation from environmental factors or latent third-party damage.

Pipe coatings used on steel mains (pre- and including 1970), 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 5.2-22** to **Figure 5.2-25** 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 (i.e., compression couplings) to join gas mains together using a fabricated fitting (i.e., 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. 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 a more rapid decline in 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.

Figure 5.2-22: Leak investigation on vintage NPS 12 gas main

Figure 5.2-23: Detail of fabricated fitting after removal

Figure 5.2-24: Multiple leaks due to severe corrosion on vintage NPS 12 gas main

Figure 5.2-25: Multiple leaks on vintage NPS 12 gas main

Figure 5.2-26 shows that for the EGD rate zone, about 70% of recorded steel main corrosion leaks in the past 13 years are from pipe installed before 1970. **Figure 5.2-26** also displays the failures normalized by pipe length for EGD confirming that corrosion leaks per kilometre are disproportionately higher than those on post-1970 pipe.

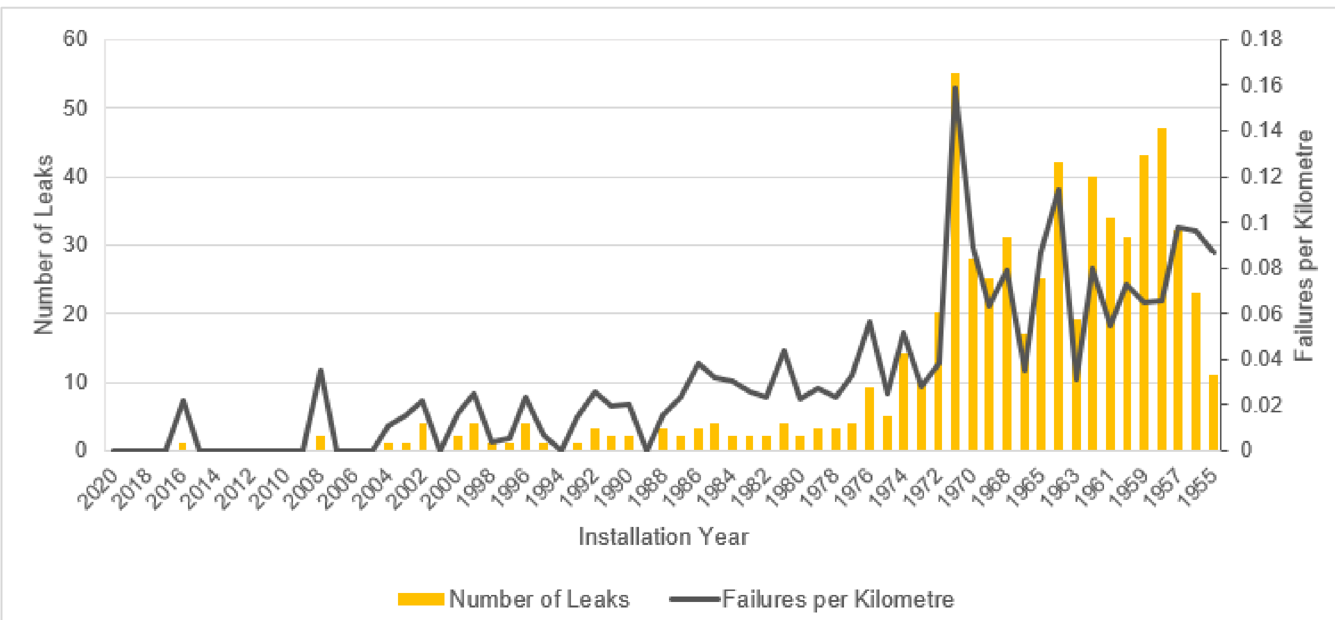


Figure 5.2-26: Steel Main Corrosion Leaks on Pipe Installed from 1955 to 2020 - EGD Rate Zone

5.2.3.4.1.2.2 Copper Services

Copper services were installed from 1960 to 1979 in the EGD rate zone only. Typical issues associated with these assets include leaks, circumferential cracks and choked flow due to buildup 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.

Annual failure rates for copper services are steadily increasing. Highest-risk copper services have been removed from the system and any remaining copper services now require replacement to prevent future failures.

5.2.3.4.1.3 Risk and Opportunity

Distribution pipe provides natural gas services to EGI's customers and runs down the streets of most residential, commercial, and industrial neighbourhoods in close proximity to buildings and dwellings.

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.

5.2.3.4.1.3.1 DIMP Risk Model

Understanding the condition and risk of the distribution pipe system has long been an industry struggle due to the vast number of assets (for EGI, this is over 32,802 km of steel mains of which over 17,423 km are Vintage Steel Mains) and the complexities associated with the distribution network geographically. According to CSA Z662 Clause 10.3.1:

> The pipeline system integrity management program required by Clause 3.3 shall include procedures to monitor for conditions that can lead to failures, to eliminate or mitigate such conditions, and to manage integrity data. Such integrity management programs shall include a description of operating company commitment and responsibilities, quantifiable objectives, and methods for:
>
> a) assessing risks
>
> b) identifying risk reduction approaches and corrective actions
>
> c) implementing the integrity management program; and
>
> d) monitoring results.

To provide insight into the Distribution Pipe system risk, EGI has recently developed a DIMP Risk Model, that adopts an analytical platform (PiMSlider) from TIMP to combine the Asset Health Review operating process reliability models (specifically the corrosion failure model for steel mains) with a geospatially-assessed consequence of failure to produce risk for each distribution main. The analytical process dynamically segments pipelines based on changes to factors (such as changes in population density, Ontario building footprints and Municipal Property Assessment Corporation [MPAC] property assessment data) that impact the consequence of a failure (in this case, the failure is a below-grade corrosion leak). The analytics follow an event tree format to assess the likelihood of several consequence streams, then aggregate all contributions into a risk value for the main. These analytics are performed systemically for all mains. The risk results can then be outputted as data tables and can be graphically represented on a GIS format map view (see **Figure 5.2-27**).

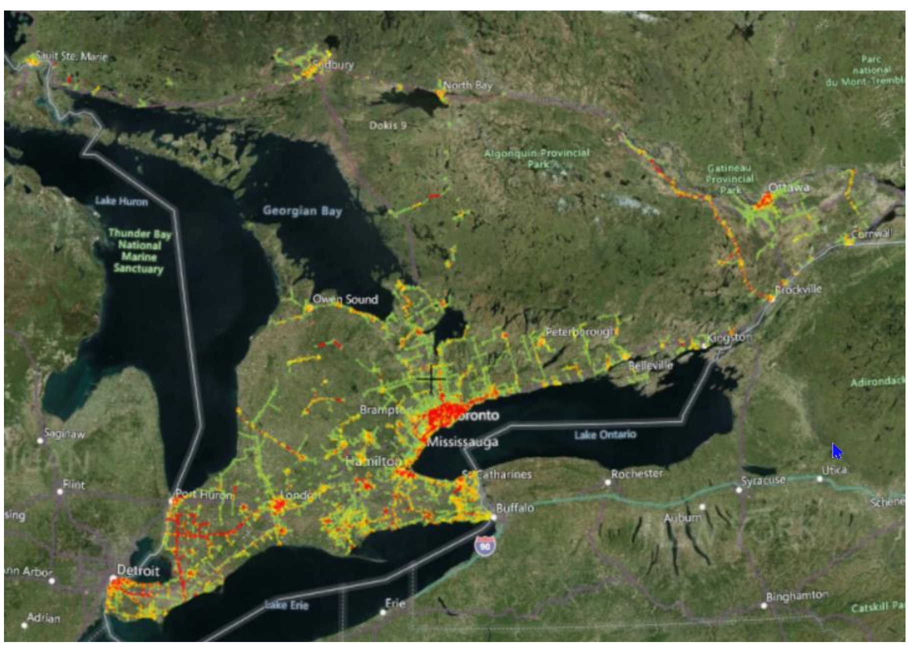


Figure 5.2-27: DIMP Risk Model output showing EGI Distribution Steel Pipe Relative Ranked Risk

Figure 5.2-27 shows the results from the DIMP Risk Model for the EGI Steel Distribution pipe system, where predicted risk is a result of combining the likelihood of a corrosion failure with the consequence of that failure. The map shows a **heat map** colouring scheme (i.e., red, orange, yellow, green) where assets are assigned a relative risk ranking based on the risk of a specific main as compared to the population. Mains coloured red represent assets with the highest predicted risk for the population. Green-coloured mains represent assets with the lowest predicted risk for the population. The colour-coded outputs assist the user to identify steel mains that pose the highest-predicted relative risk for the population. The platform allows the user to create systemic risk views for current or future years, based on the reliability curves from the Asset Health Review Reliability Models. **Figure 5.2-27** shows the predicted relative risk of steel mains in 40 years for the EGI Distribution network.

As previously discussed and demonstrated the pre- and including 1970 Vintage Steel population is expected to experience increased corrosion based failures in the near future, creating increased risk for EGI, possible reductions in reliability and service for EGI's customers, and increased Greenhouse Gas (GHG) emissions. 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.

5.2.3.4.1.3.2 Copper Services

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, GHG emissions and customer outages.

5.2.3.4.1.3.3 Aerial Crossings

Aerial crossings are segments of unsupported steel pipe that span water crossings and ditches. These are from legacy construction practices from the Union distribution network; and over time, the condition of these aerial crossings has degraded. Since they are aboveground pipe segments, the cathodic protection barrier is not effective; so, corrosion initiation sites are able to progress unchecked. The coatings have degraded over time as well; erosion in many locations has increased unsupported spans. There may also be mechanical couplings present that can experience pull-outs with ground movement. Third-party damages continue to be problematic for these exposed pipe segments.

The risk for these degrading unsupported aerial crossings is through corrosion leaks, third-party damages, environmental damages from fallen trees or waterborne debris, potential pipe failures due to mechanical fitting pull-out, or potential pipe failure due to unsupported stress to the pipe. Some of these mains supply a significant number of downstream customers, so a failure could result in loss of gas supply for these customers while repairs are performed.

Failures as described above are increasing as these degradation factors have fueled the deterioration of these pipe segments. Some recent failures have resulted in loss of gas supply to hundreds of customers.

5.2.3.4.2 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 15,381 km of steel mains for EGI (see **Figure 5.2-5** and **Figure 5.2-6**). 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 as shown in **Figure 5.2-24**.

5.2.3.4.2.1 Condition Methodology

See **Section 5.2.3.4.1.1**.

5.2.3.4.2.2 Condition Findings

These mains are exposed to some of the same issues as steel mains from 1970 and earlier (see **Table 5.2.3-3**). 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 pipe population for the EGD and Union rate zones is shown in **Figure 5.2-28** and **Figure 5.2-29** respectively.

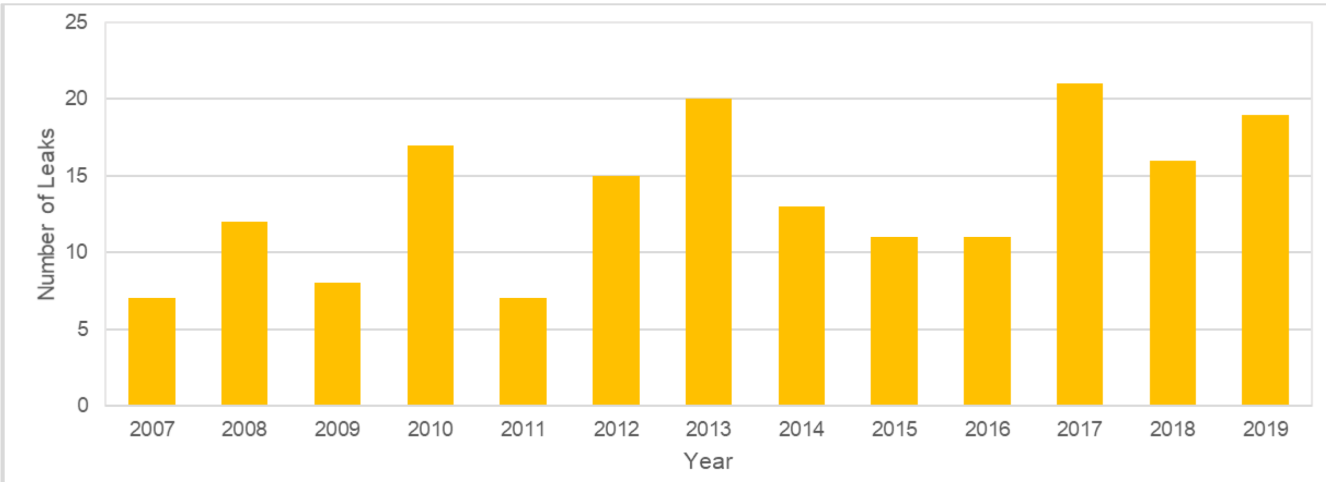


Figure 5.2-28: Historical Steel Main Corrosion Leaks (Post-1970) – EGD Rate Zone

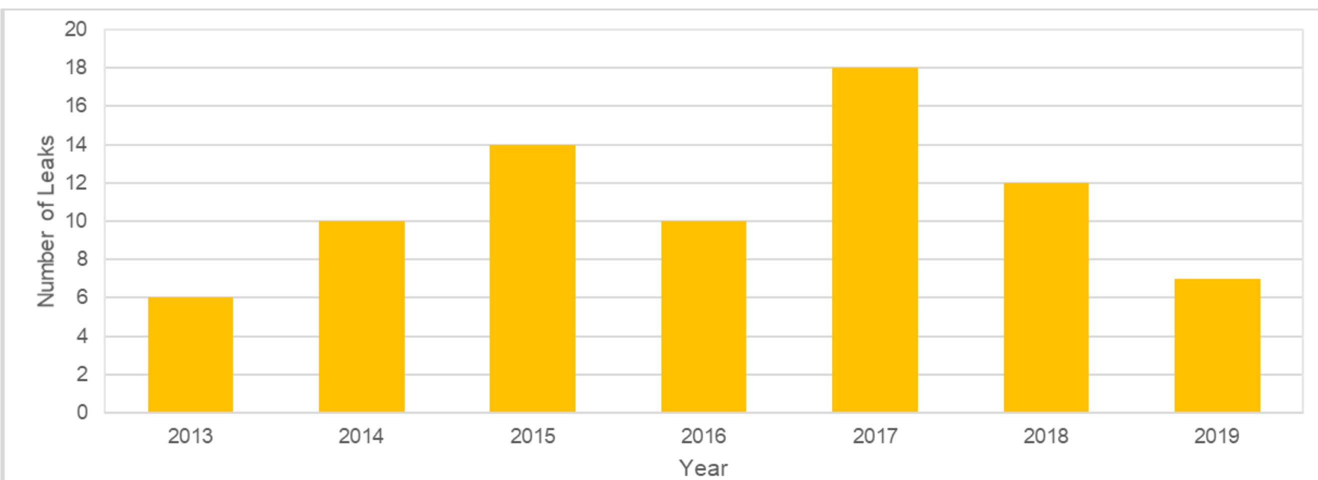


Figure 5.2-29: Historical Steel Main Corrosion Leaks (Post-1970) – Union Rate Zones

5.2.3.4.2.3 Risk and Opportunity

As demonstrated by the projected leak trends in **Figure 5.2-30** and **Figure 5.2-31**, 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 and environmental conditions) may accelerate degradation and result in leaks. These carry the same risks noted for pre- and including 1970 steel mains (see **Section 5.2.3.4.1**), 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.

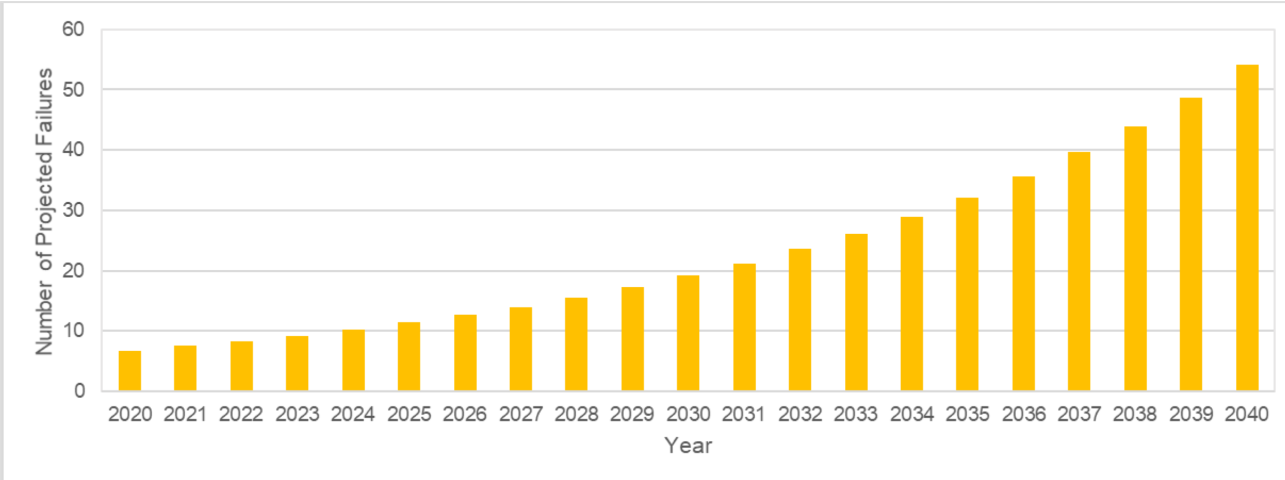


Figure 5.2-30: Post-1970 Steel Mains Corrosion Leak Projections (2020 to 2040) – EGD Rate Zone

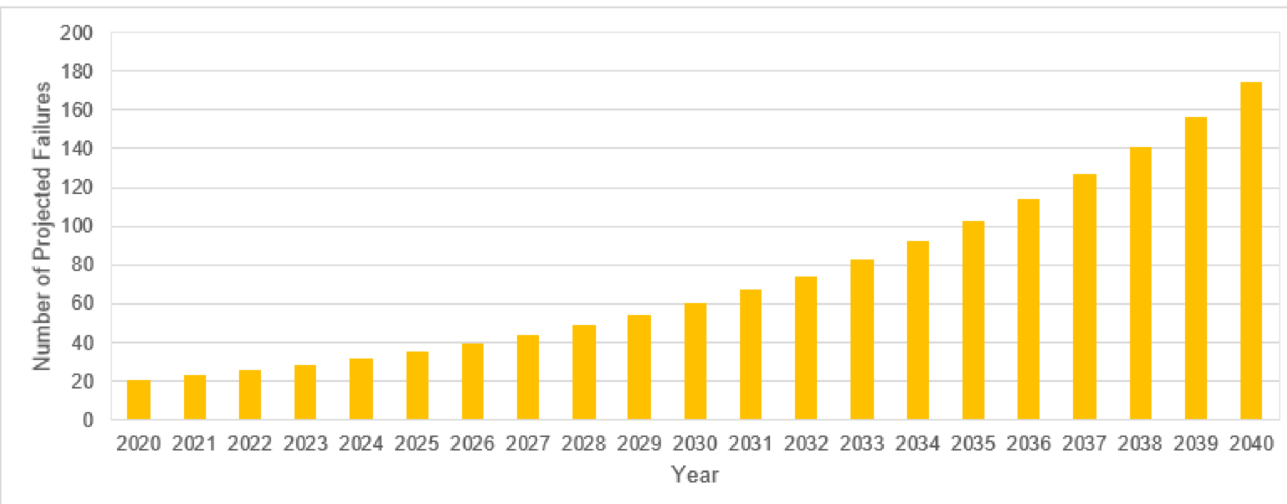


Figure 5.2-31: Post-1970 Distribution Steel Pipe Corrosion Leak Projections (2020 to 2040) – Union Rate Zones

5.2.3.5 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: (1) Vintage Plastic Aldyl A, (2) Intermediate Plastic Mains and (3) Modern Polyethylene (PE) Resins. In some instances, records are not clear on if 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 5.2-32** and **Figure 5.2-33** respectively.

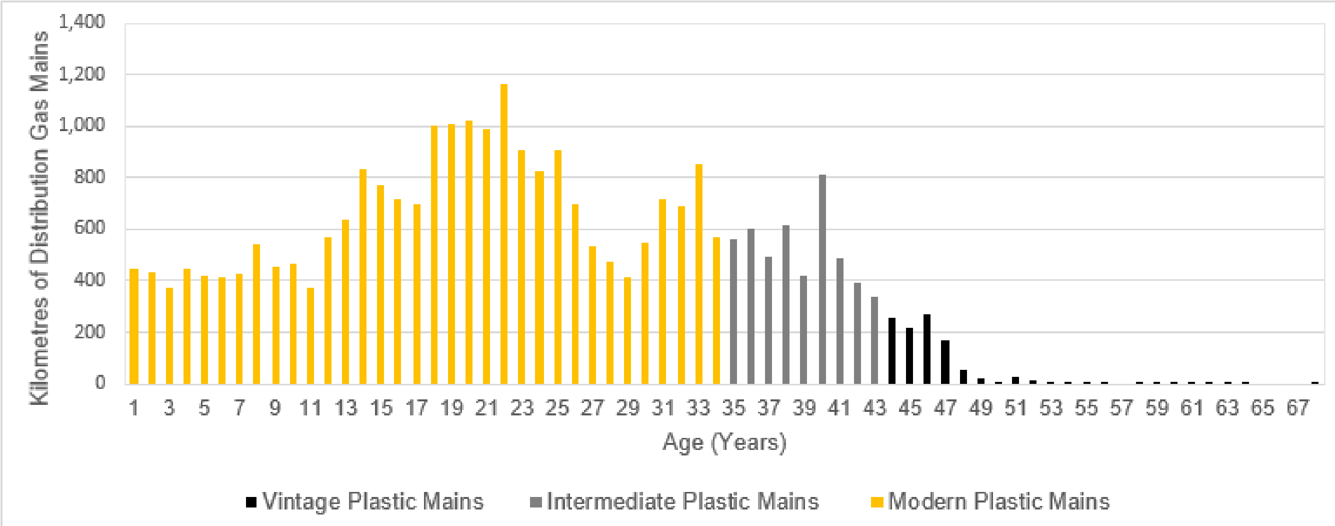


Figure 5.2-32: Age Distribution - Plastic Pipe: EGD Rate Zone

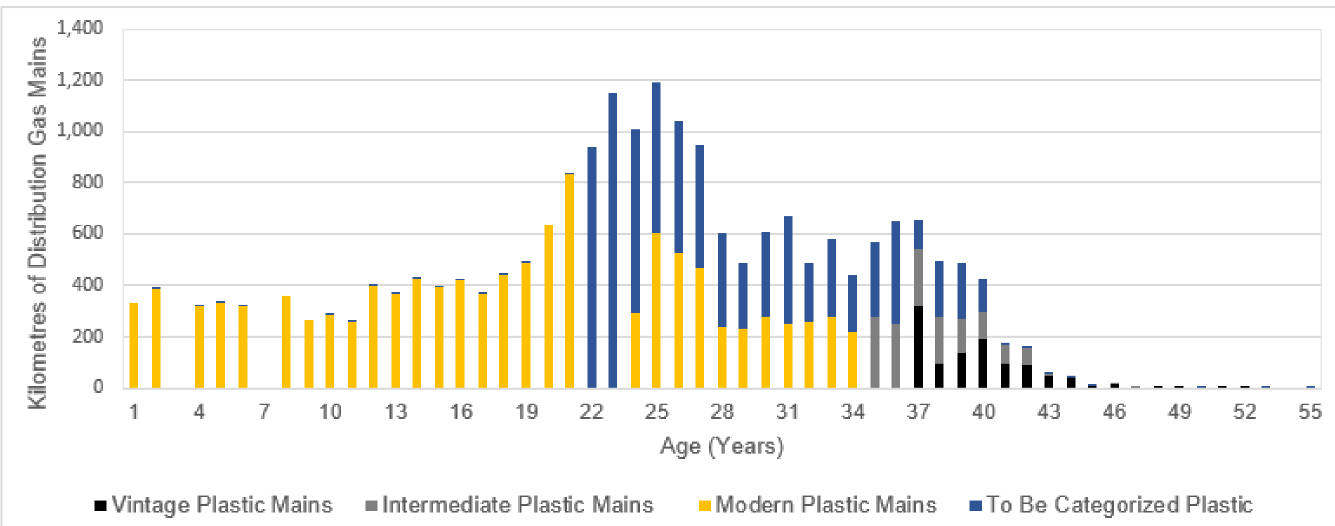


Figure 5.2-33: Age Distribution - Plastic Pipe: Union Rate Zones

Copper risers are also discussed in this section as they are primarily associated with Vintage Plastic Aldyl A and Intermediate Plastic Mains systems. Copper risers on these systems include an AMP-fitting (i.e., a mechanical transition fitting between the plastic service and the copper riser). These assets were installed between 1969 and 1984 in the EGD rate zone only. **Figure 5.2-34** illustrates the calendar age of the copper riser population for the EGD rate zone as of 2019.

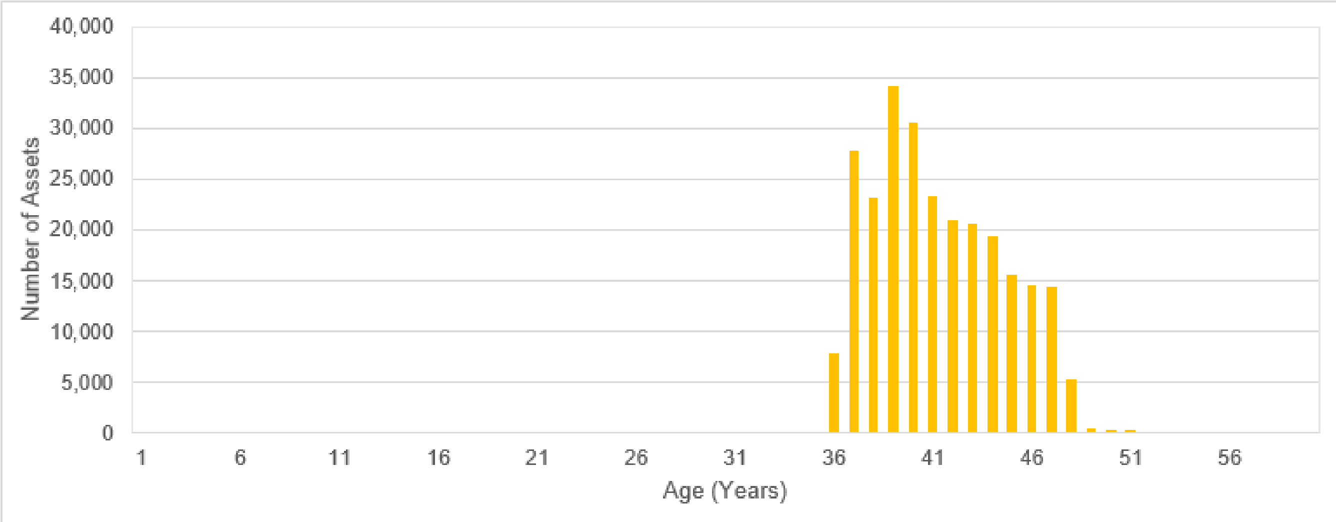


Figure 5.2-34: Age Distribution – Copper Risers: EGD Rate Zone

Note: Condition Methodology and **Risk and Opportunity** are consistent across plastic pipe assets. Asset subclasses are discussed in detail in Condition Findings only.

5.2.3.5.1 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 Quality Material Equipment Reports [QMER]) identify and assess the failure mechanisms of EGI's assets. EGI has also concluded an extensive study on vintage plastic Aldyl A pipe with the Gas Technology Institute (GTI) to develop data-driven predictions on the remaining useful life expectancy of plastic pipe. Studies are now being extended to Intermediate Plastic Mains 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 2023.
- **Tacit knowledge (subject matter advisors [SMAs] / worker input)**: Field knowledge is used to identify potential condition issues through regular meetings with SMAs.
- **Reliability modelling**: A reliability model has been developed for vintage plastic Aldyl A pipe and copper risers through the Asset Health Review (AHR) operating process under the 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.

5.2.3.5.2 CONDITION FINDINGS

The methodologies described in **Section 5.2.3.5.1** drive condition findings for the following subclasses: Vintage Plastic Aldyl A, Vintage Plastic Intermediate Plastic Mains, Copper Risers, and Modern PE Resins.

5.2.3.5.2.1 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 (see **Figure 5.2-35**). 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 cause 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.

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.

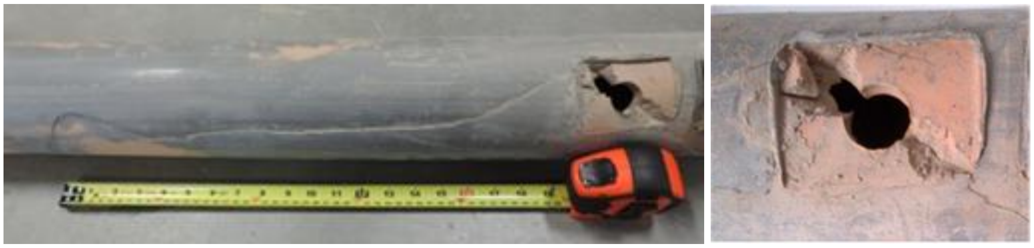


Figure 5.2-35: Rapid Crack Propagation on Aldyl A Pipe from Saddle Tee Fusion (Mississauga, ON)

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 slow rise in expected failures over the next 20 years. Leak projections based on historic failure rates for the asset subclass are shown in **Figure 5.2-36** for EGD and **Figure 5.2-37** for the Union rate zones.

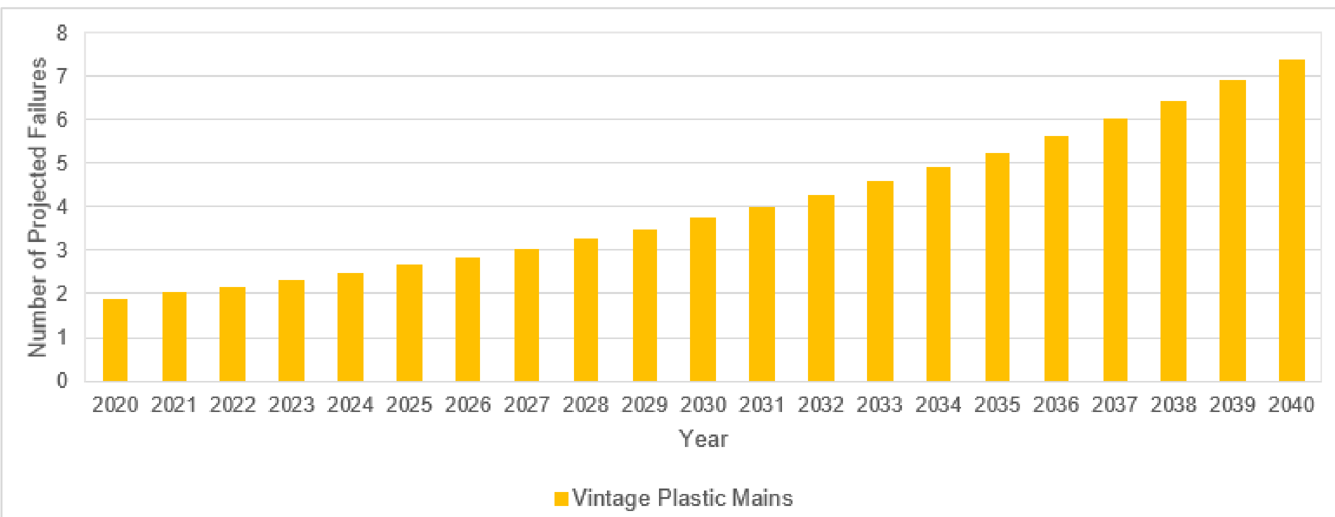


Figure 5.2-36: 20-Year Projection: Vintage Plastic Aldyl A Mains Failures (2020-2040) EGD Rate Zone

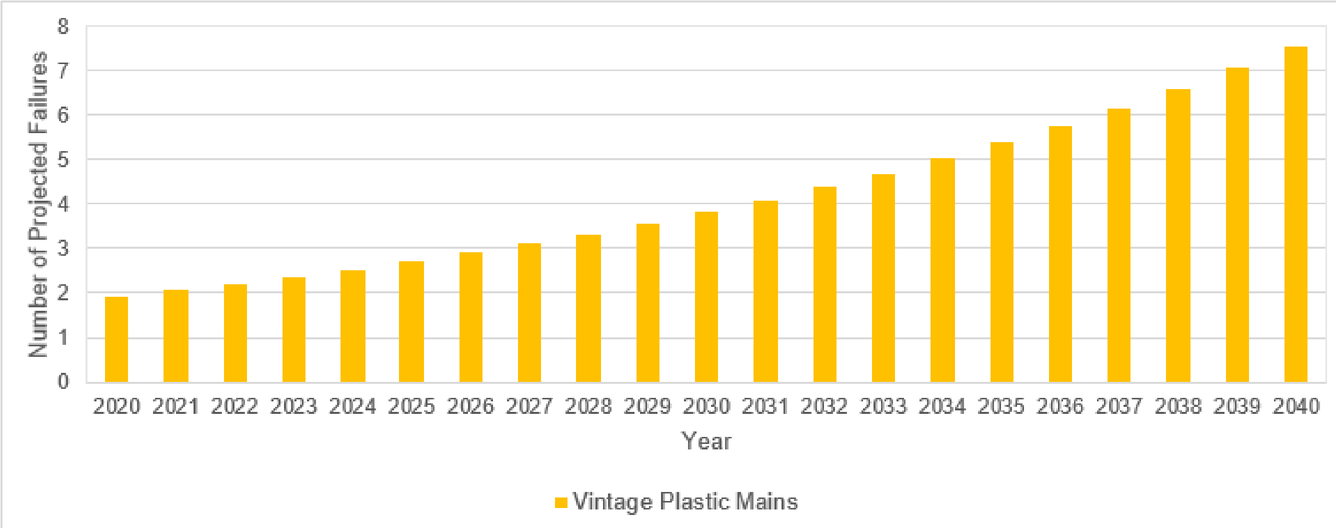


Figure 5.2-37: 20-Year Projection: Vintage Plastic Aldyl A Mains Failures (2020-2040) Union Rate Zones

The current population of vintage plastic Aldyl A mains is in generally good condition as is represented by the reliability models and shown in the Mean Cumulative Function (MCF) curves in **Figure 5.2-38** for EGD and **Figure 5.2-39** for the Union rate zones. These graphs indicate that EGI can expect relatively low failure rates for another 30 years before the rate is projected to dramatically increase. This is in contrast to the steel pipe MCF graphs **Figure 5.2-20** and **Figure 5.2-21** that show significant increases to failure rates in less than 10 years for pre- and including 1970 vintage steel.

Results of various laboratory testing conducted on EGI samples as well as samples from other utilities yielded parameters required to estimate the time to failure of vintage plastic Aldyl A pipes using a mechanical model known as Rate Process Method (RPM). Due to the large bounds of the RPM model and lack of sufficient EGI failure data, a Bayesian approach was used to integrate existing mechanical and statistical models and make EGI's reliability estimates more accurate. Overall, the results of the Bayesian model yield moderate failure projections for vintage plastic Aldyl A pipes in upcoming years. The Bayesian model has changed EGI's understanding of the future failure rates for Aldyl A. In previous Asset Plans, EGI showed how the company's previous information and models yielded more aggressive failure curves.

Although natural gas distribution utilities in the southern United States have made the replacement of Aldyl A pipe a priority, EGI has not yet observed any signs of significant increases to failures, likely due to the colder soil temperatures that increase the life expectancy for this plastic.

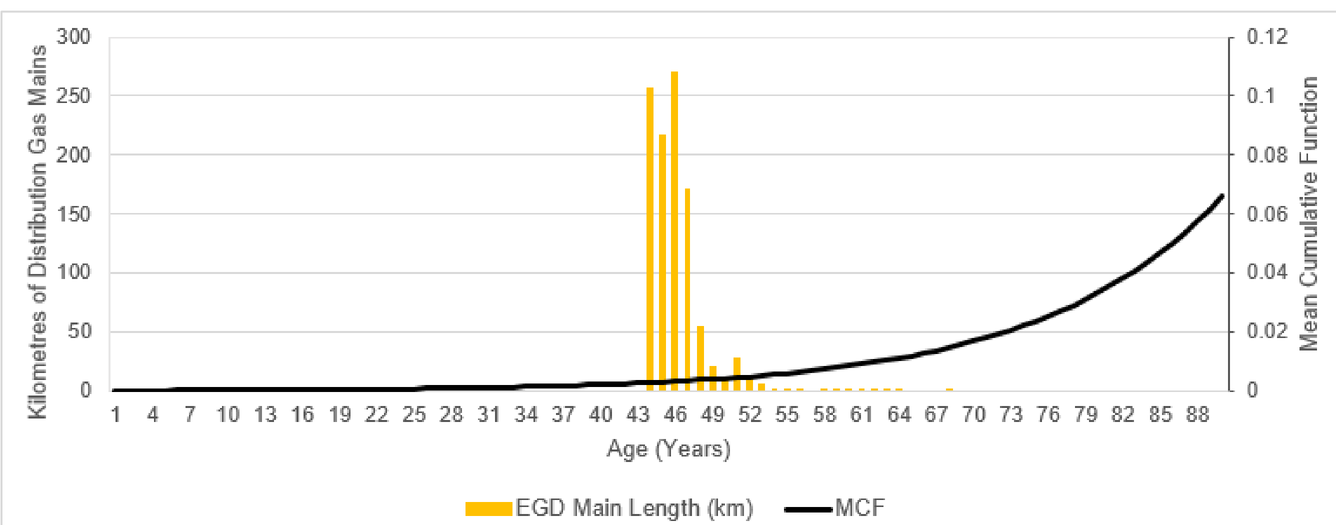


Figure 5.2-38: Installation History vs. MCF – Vintage Plastic Mains EGD Rate Zone

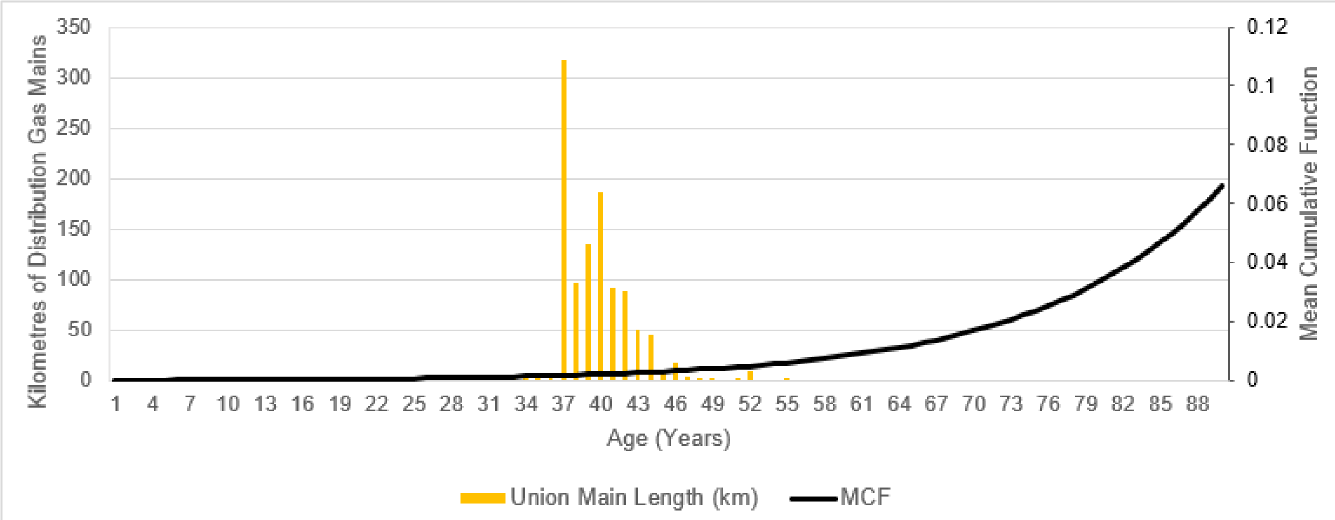


Figure 5.2-39: Installation History vs. MCF - Vintage Plastic Union Rate Zones

5.2.3.5.2.2 Intermediate Plastic Mains

After using vintage plastic Aldyl A pipe, EGI transitioned to installing other resin-based plastic pipes designated as Intermediate Plastic Mains, 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 Intermediate Plastic Mains pipe was introduced.

Intermediate plastic 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 intermediate plastic material. The installation year for this population extends until 1998. Excluding pipe designated as To Be Categorized Plastic, the current asset age of Intermediate Plastic Mains pipe ranges from 32 to 40 years and 34 to 42 years for the EGD and Union rate zones respectively (see **Figure 5.2-40** and **Figure 5.2-41**).

Currently, there is no known industry research or investigation completed on intermediate 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. These samples are in the process of undergoing testing and analysis in 2022 and final reports should be available to EGI in 2023.

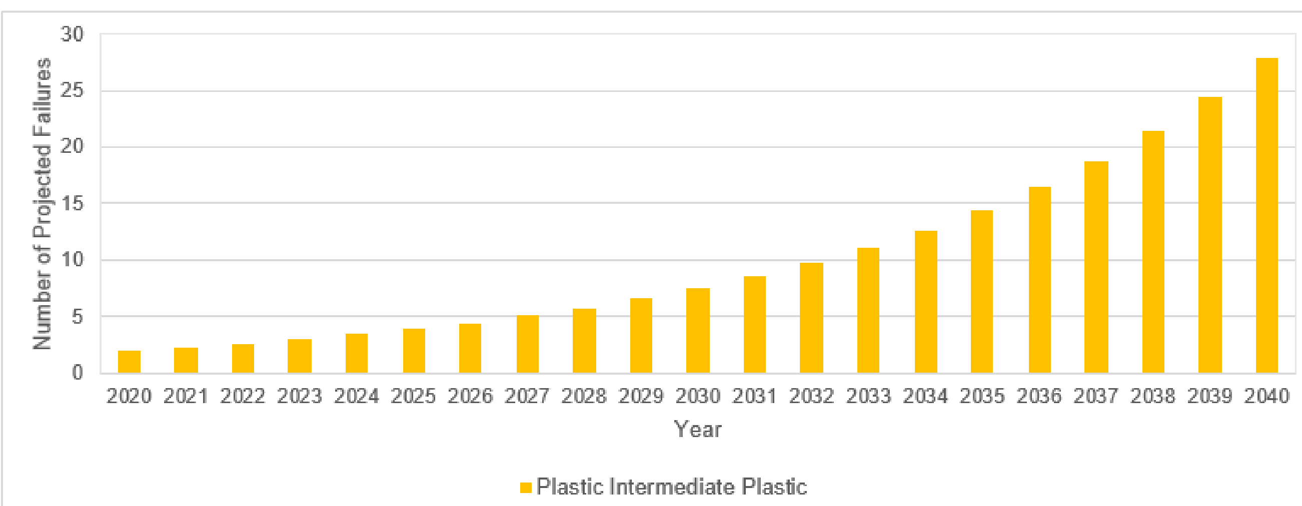


Figure 5.2-40: 20-Year Projection – Plastic Intermediate Plastic Mains Failures (2020 to 2040) – EGD Rate Zone

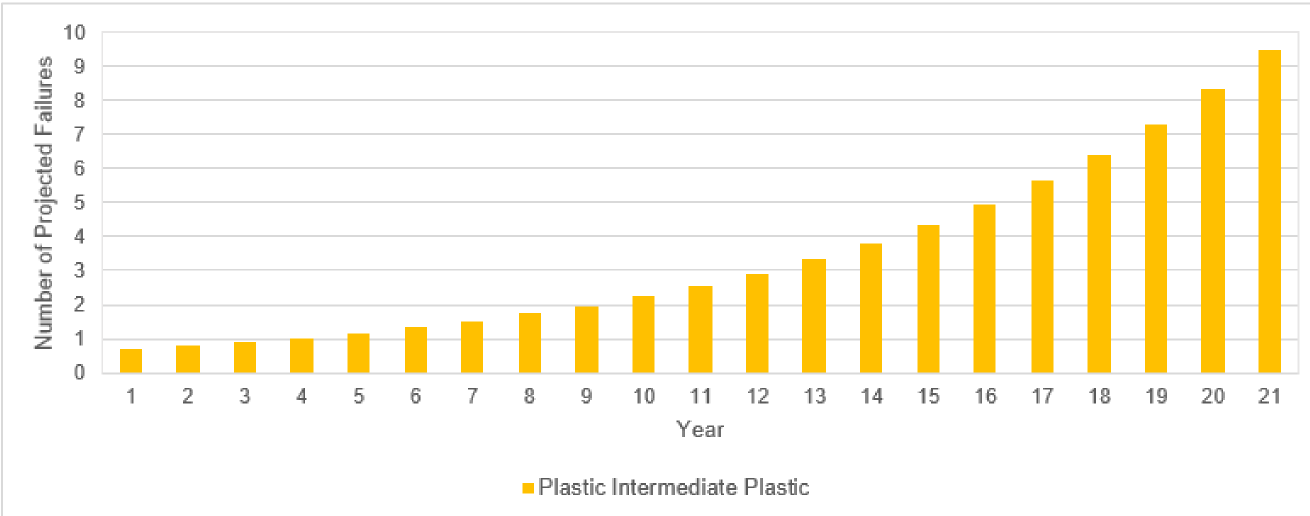


Figure 5.2-41: 20-Year Projection – Plastic Intermediate Plastic Mains Failures (2020 to 2040) Union Rate Zones

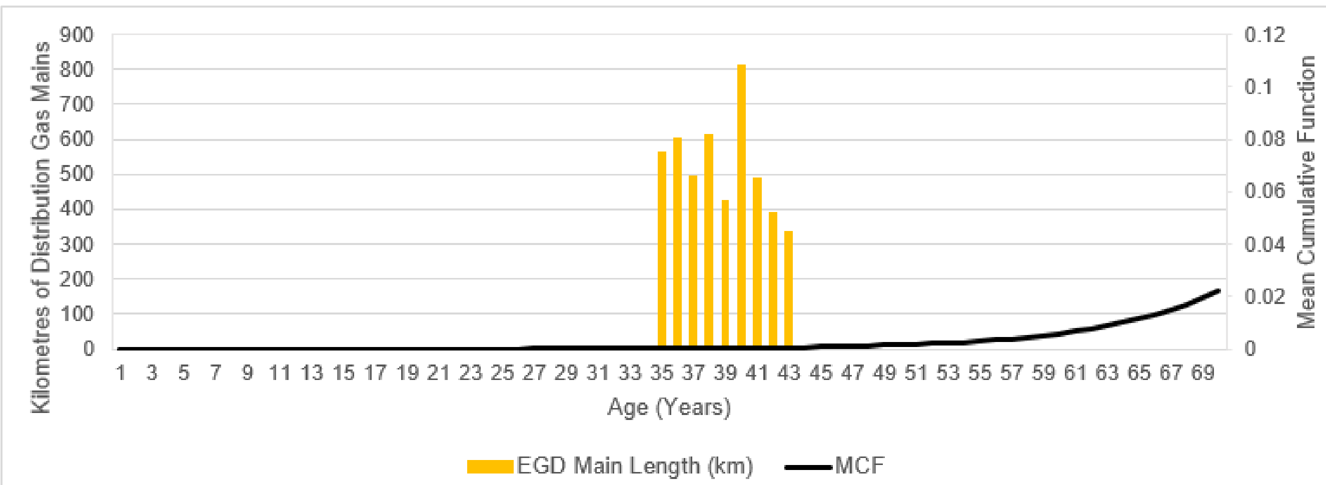


Figure 5.2-42: Installation History vs. MCF – Plastic Pipe Intermediate Plastic – EGD Rate Zone

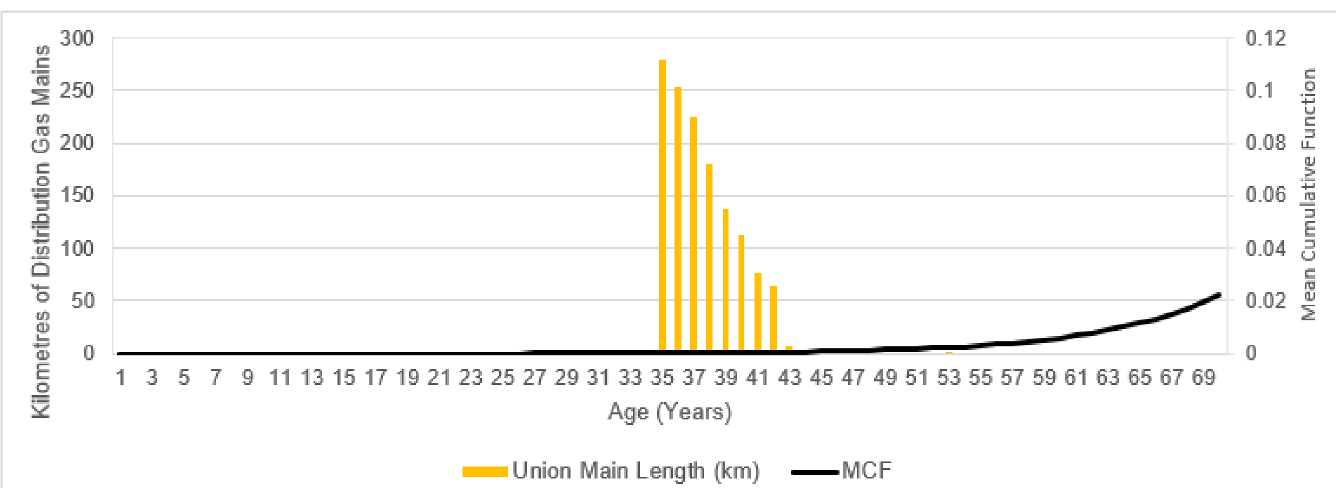


Figure 5.2-43: Installation History vs. MCF – Plastic Pipe Intermediate Plastic – Union Rate Zones

5.2.3.5.2.3 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 5.2-44**, **Figure 5.2-45** and **Figure 5.2-46**.

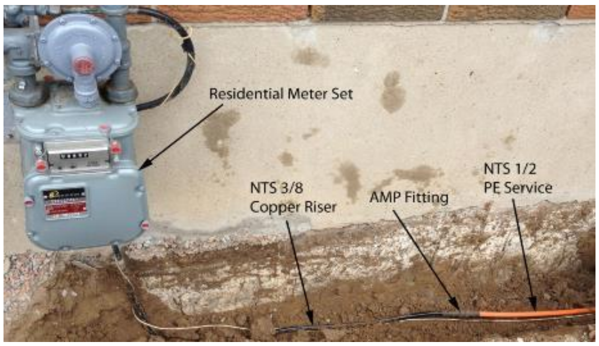


Figure 5.2-44: AMP Fitting Assembly

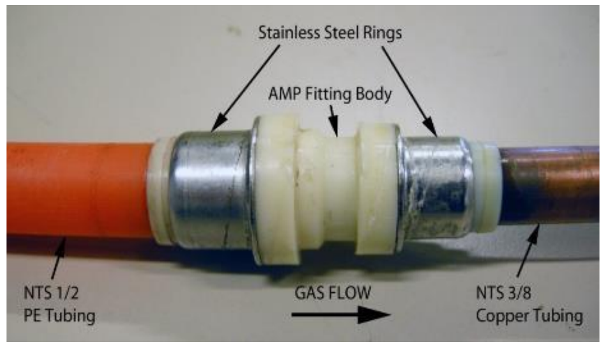


Figure 5.2-45: Typical AMP Fitting Installation

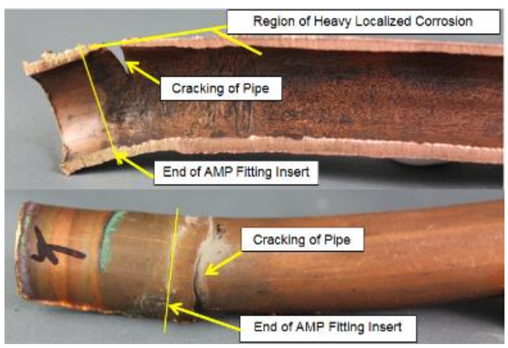


Figure 5.2-46: Localized Corrosion Failure at AMP Fitting Outlet

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 5.2-47.** Actual failure data has trended very closely to the statistically projected number of leaks as shown in **Figure 5.2-48**.

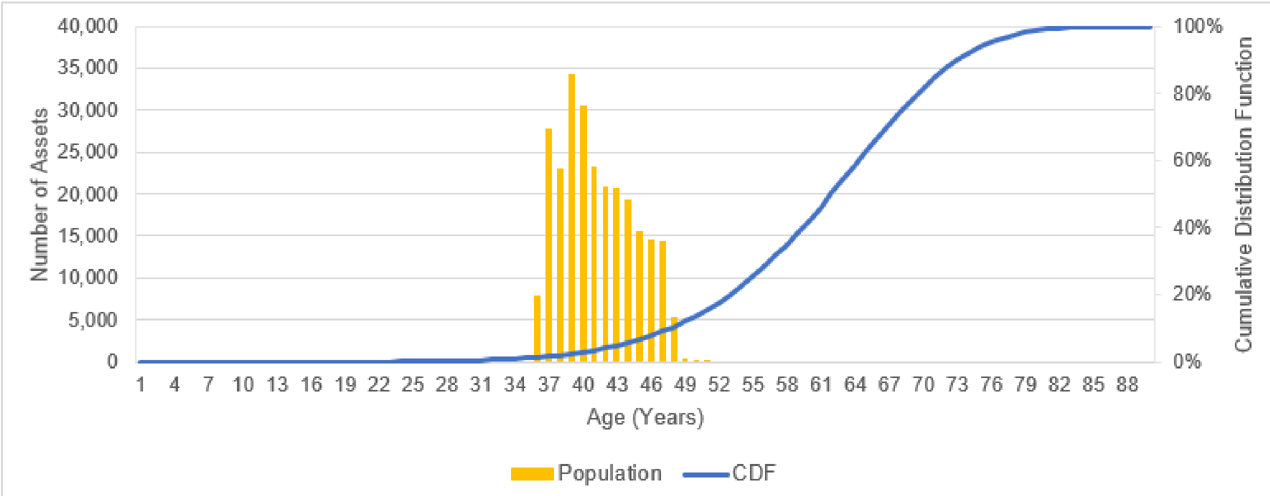


Figure 5.2-47: Population of Copper (AMP) Risers vs. CDF – EGD Rate Zone

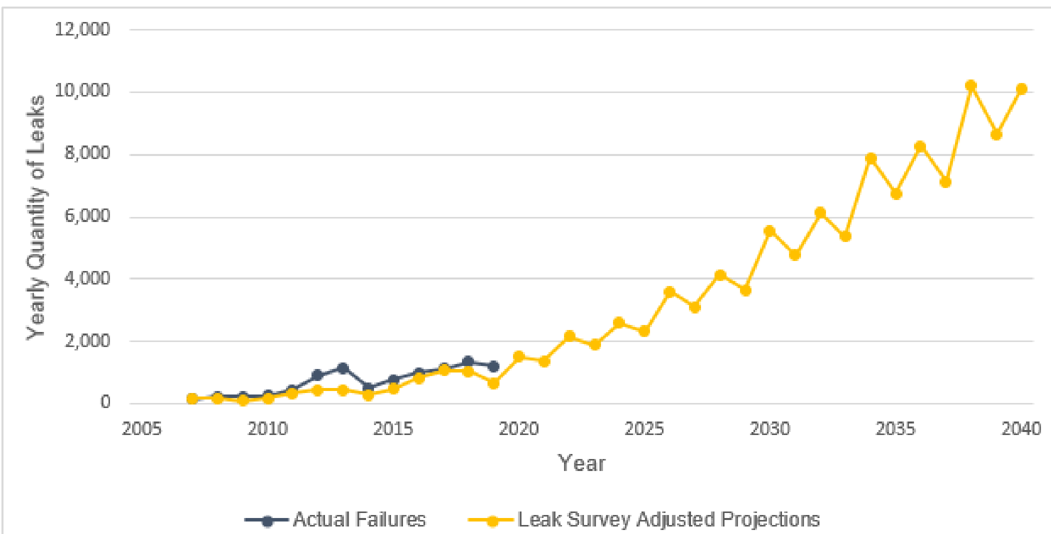


Figure 5.2-48: Copper Riser Discovered Leaks

5.2.3.5.2.4 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.

5.2.3.5.3 RISK AND OPPORTUNITY

As demonstrated by the projected leak trends, the three categories of PE mains population are performing well and are expected to continue to perform well in future years, with leak rates that do not pose a significant risk. Mains are in good condition; however, some hazards (third-party latent damages and environmental conditions) may accelerate degradation and result in leaks. These carry the same risks noted for steel mains (see **Section 5.2.3.4.1**), including supply interruption to customers and GHG 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.

5.2.3.6 Distribution Pipe Strategy Outcomes

5.2.3.6.1 TIMP MAINS STRATEGIES

The Transmission Integrity Management Program (TIMP) pipelines strategy is to continue performing in-line inspections (ILI) including retrofits to enhance the amount and quality of condition data and digs to evaluate pipeline features. Depth of cover surveys and class location surveys are also included as part of the TIMP pipelines strategy and any changes in class location or depth of cover are assessed to determine if mitigations are required.

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. Where inspection data cannot be obtained by known techniques as in the case of pre-1970 vintage steel, full replacement of pipelines is used to mitigate high level of uncertainties associated with the continuous operation of these high pressure pipelines.

As EGI further develops and extends its Integrity Management Program (IMP), condition issues are identified and assessed to establish the appropriate remediation and timing. Examples that are emerging at this time include depth of cover, exposure of pipelines in and near watercourses, as well as pipelines that are located on bridge crossings.

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:

5.2.3.6.1.1 Inspection Program Integrity Retrofits and Digs

Investments in TIMP retrofits and digs are mandated by the 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.

EGI inspects 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. The following investment has been identified within this program:

Sudbury Lateral Integrity Digs 2023

The NPS 10, 121 km Sudbury Lateral Section 1 was constructed in 1958 and operates above 50% SMYS as a TIMP pipeline. This pipeline runs from North Bay (Barnett Road TC tap) to Coniston PCS feeding Sudbury and smaller adjoining communities. The pipeline section was in-line inspected in 2021 with several Phase 2 features (corrosion with metal loss, and dents, etc.) reported. 67 digs have been planned for the 2023 integrity dig works to effect repair or replacement of affected sections. See **Appendix A, Pg. 17** for additional detail on this investment.

5.2.3.6.1.2 Depth of Cover Program

In compliance with *TSSA Oil and Gas Pipeline Systems Code Adoption Document*, EGI has a depth of cover survey program for all TIMP 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.

5.2.3.6.1.3 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 near 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.

5.2.3.6.2 COMMON DISTRIBUTION PIPE ASSET STRATEGIES

The strategies grouped together here apply to a number of different asset subclasses.

5.2.3.6.2.1 Corrosion Prevention Program

This program consists of annual anode installations and rectifier installations. In addition to active steel mains, the Corrosion Prevention Program also covers corrosion control on steel casings and replacement of rectifier systems, and coating and renewal work on bridge crossings.

- **Anodes and rectifiers:** Program 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, additional or replacement rectifiers, and groundbeds.
- **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.

5.2.3.6.2.2 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 and water mains.

- **Leaking 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.

5.2.3.6.2.3 General Replacement Program

This program addresses planned main replacement work that are not emergency repairs. The capital expenditures included in this category cover a variety of planned projects. The projects covered under this expenditure include low-pressure system replacements, distribution pipeline replacements due to historical leakage and integrity concerns (like MOP Verification Program spend), pipeline casing replacements, and bridge and water crossing replacements and repairs. These projects are often identified through planned inspections and pipeline surveys. They would then be assessed and planned based on risk and resource availability.

5.2.3.6.2.4 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.

5.2.3.6.2.5 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 or building, 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.

5.2.3.6.2.6 Continuous Improvement of Reliability Models and Asset Understanding

Condition assessment programs: Condition assessment programs including integrity assessments and QMER are used to identify and assess the failure mechanisms of EGI's assets. EGI has also concluded an extensive study on vintage plastic Aldyl A pipe with the Gas Technology Institute to develop data-driven predictions on the remaining useful life expectancy of plastic pipe. Studies are now being extended to Intermediate Plastic Mains 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.

Reliability modelling: A reliability model has been developed for vintage plastic Aldyl A pipe and copper risers through the Asset Health Review operating process under the Distribution Integrity Management Program. 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 subject matter advisor input.

5.2.3.6.3 STEEL MAINS (PRE- AND INCLUDING 1970) STRATEGIES

The approach for the Steel Mains (Pre- and including 1970) asset subclass consists of program work that includes condition monitoring, a reactive repair program, and proactive and reactive replacement programs.

EGI continues to evaluate load shed zones (system isolation) 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 5.2.3.2** and the resultant replacement/renewal strategies for the Steel Mains (Pre- and including 1970) asset subclass are as follows:

5.2.3.6.3.1 Bare and Unprotected 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, of which approximately 5% 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.

5.2.3.6.3.2 Vintage Steel Replacement Program

EGI has developed a Proactive Vintage Steel Replacement Program to mitigate the predicted future risk that results from some of EGI's oldest steel mains reaching the end of their useful life and beginning to fail. The goal of the Proactive Vintage Steel Replacement Program is to avoid the risk that these aging assets pose by renewing them before they fail; this is in accordance with the expectations set out by the Safety and Loss Management System contained within CSA Z662-19. As depicted in **Figure 5.2-24**, the population of Vintage Steel has a failure rate almost 3 times the failure rate of more modern steel pipe and is expected to increase exponentially over the next 20 years. The rate of renewal will not be able to match the rate of failing pipe if EGI were to take a reactive stance to this issue. EGI has chosen to take a proactive mitigation approach to the aging steel population which is consistent to the approach many natural gas distribution utilities are taking in the North American natural gas distribution industry[9].

The Proactive Vintage Steel Replacement Program at EGI seeks to follow industry best practices[10], as noted above, to create a master plan and program to identify and proactively replace pipe that is at elevated risk of failure through an ongoing risk-based fitness for service assessment.

With the lens of the new DIMP Risk Model, most of the Vintage Steel mains population are predicted to remain in the Low Risk region (see **Figure 5.2-49**) well into future years. Leveraging the DIMP Risk Model outputs for steel mains and comparing the predicted future risk against the Enbridge Risk Matrix (see **Figure 4.2-4**), assets that move into the yellow medium risk zone are targeted for replacement within the program (see **Figure 5.2-49**).

[9] Washington UTC – Commission Policy on Accelerated Replacement of Pipeline Facilities with Elevated Risk (December 31, 2012)
[10] The American Gas Foundation – Gas Distribution Infrastructure: Pipeline Replacement and Upgrades (July, 2012)

Medium	Medium	High	Very High	Very High	Very High	Very High
Medium	Medium	Medium	High	Very High	Very High	Very High
Low	Medium	Medium	Medium	High	Very High	Very High
Low	Low	Medium	Medium	Medium	High	Very High
Low	Low	Low	Medium	Medium	Medium	High
Low	Low	Low	Low	Medium	Medium	Medium
Low	Low	Low	Low	Low	Medium	Medium

Figure 5.2-49: Vintage Steel Mains Selection Process

This selection process identifies approximately 5,100 km of the 17,423 km of Vintage Steel mains for renewal based on their predicted future risk. The Proactive Vintage Steel Replacement Program proposes renewing these targeted mains over a 20-year term. This would equate to renewing about 253 km/year after ramping up to full pace. It is expected that the program ramp-up will take five years to reach full volumes. The predicted failure rates and risks for the targeted mains (5,100 km) are shown in **Figure 5.2-50** and **Figure 5.2-51.** A **do-nothing** scenario shows a significant increase to leak rates and risk for the company should a more reactive stance be taken. By taking proactive action, EGI can reduce the number of below-grade leaks experienced within the distribution network as well as eliminate the risk that those below-grade leaks may pose.

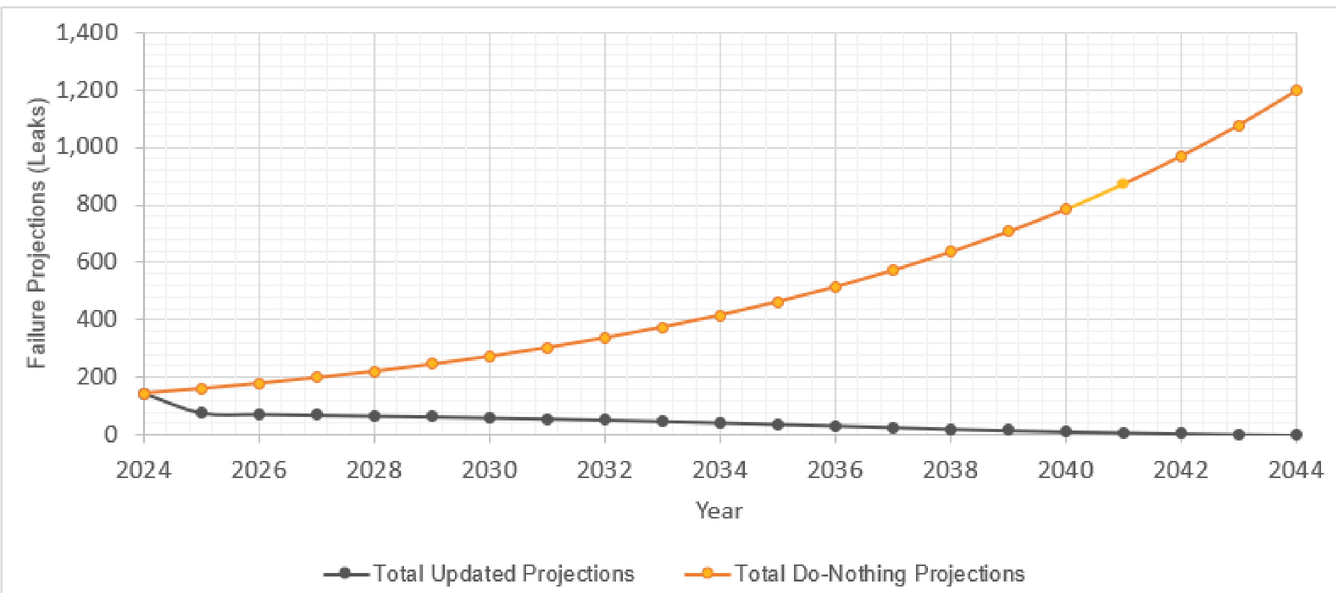


Figure 5.2-50: Predicted Failure Projections – Targeted Mains within the Program (5,100km)

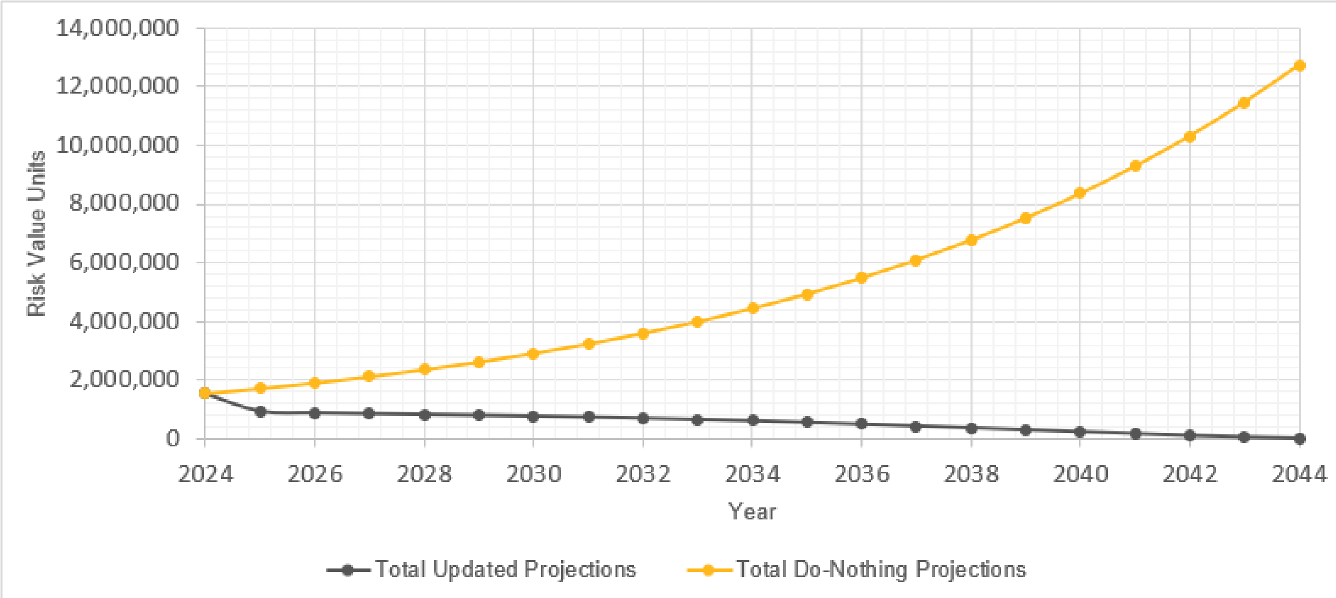


Figure 5.2-51: Predicted Risk Reduction for the Proactive Vintage Steel Replacement Program

The vast majority (over 80% of steel mains) of distribution steel pipe being targeted within the Proactive Vintage Steel Replacement Program is small diameter (NPS 6 or smaller) intermediate pressure (MOP 64 psi or less) pipe that will be replaced by PE pipe, eliminating the corrosion leak risk, removing cathodic protection and cathodic protection survey costs. Replacing aging steel pipe with PE pipe will better equip the distribution network for transition to hydrogen blending. Renewing aging steel pipe before it leaks will also assist EGI in reducing greenhouse gas emissions.

By proactively replacing aging assets, in addition to avoiding significant risk, savings can be achieved as planned work can be executed with less cost than emergency work once a leak has occurred. A proactive vintage steel replacement program will assist EGI in sustaining EGI's current reliability levels and to prepare the network for the eventual delivery of low carbon, blended hydrogen. This program was included in the 2024 Rate Rebasing Customer Engagement, where the majority of customers agreed that EGI should increase its spending on the Vintage Steel Program in order to prepare the system for the future.

The projects created to support the Vintage Steel Program will initially be prioritized based on the following factors:

- Relative risk in comparison to other projects within the program.
- Opportunities to combine with other pipe replacement programs such as Relocations.
- Planned moratoriums which will limit the ability to execute projects for a specified period of time.

The LTC decision for St. Laurent is not expected to impact the Vintage Steel Replacement Program as this program and the associated selection of pipe replacements are based off of predictive analytics (condition and risk from the DIMP Risk Model as described in **Section 5.2.3.4.1.3.1**). This program is a proactive approach replace deteriorating piping at a planned and manageable pace before the rate of deterioration and failure exceeds EGI's ability to respond to such failures.

Additionally, as studies to support the hydrogen strategy are finalized and new areas targeted for hydrogen injection are identified, these will be given priority among the other considerations.

5.2.3.6.3.3 Major Pipe 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 Ontario Energy Board's Leave-to Construct process.

Analytics, failure history, tacit knowledge and condition assessments have identified condition and risk issues with some of EGI's more significant distribution mains. In response to the St. Laurent Decision (EB-2020-0293) and direction from the OEB, EGI will evaluate the viability, cost and effectiveness of alternate inspection and maintenance methods on these distribution pipelines. Failures 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 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 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 5.2.3-1**. Should the NPS 12 St. Laurent main experience a pipeline defect or sustain damage, EGI may 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 on customers and residents. Shutting down the pipeline could lead to customer loss in excess of 60,000 on a cold day. **Figure 5.2-52** to **Figure 5.2-54** show areas in the St. Laurent pipeline that exhibit poor condition.

Following the OEB decision in May 2022, EGI is undertaking a series of field activities to further evaluate the condition of this distribution line. This includes comprehensive external corrosion surveys, recurrent leak surveys and odourant verification tests, opportunistic digs, in-line inspections of various, representative segments of the line, and non-destructive examinations. In parallel, EGI is currently evaluating impacts from an Integrated Resource Planning (Energy Transition) perspective and is planning related discussions with the impacted municipality. Obtaining such evidence is in line with the recommendation from the OEB's Decision and will provide factual data to determine the next steps for this and similar projects without prejudice. While the outcome of the further condition evaluation and IRP opportunities were not fully understood at the time the capital requirements for the project were adjusted in the capital forecast; EGI is still expecting a relatively large capital investment will be necessary to address the pipeline condition and continue to safely and reliably serve the current and future energy needs for the City of Ottawa.

See **Appendix A, Pg. 9-10** for additional detail on this investment.

Figure 5.2-52: Multiple corrosion sites on NPS 12 St. Laurent pipe

Figure 5.2-53: Gouges and dents due to latent damages

Figure 5.2-54: Coating damages

Port Stanley Line

The NPS 8 Port Stanley line was constructed in 1959 and is approximately 20 km 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 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 as discussed in **Table 5.2.3-1**.

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 5.2-55 to **Figure 5.2-57** show areas in the Port Stanley line exhibiting factors that can lead to difficulty in maintaining the pipeline, poor condition and increased risk. See **Appendix A, Pg. 16** for additional detail on this investment.

Figure 5.2-55: Corrosion

Figure 5.2-56: Exposed Crossing

Figure 5.2-57: Below-Grade Stations

NPS 12 Martin Grove Rd

The NPS 12 Martin Grove Rd project addresses condition and risk concerns for approximately 6.4 km of 1955-installed vintage steel pipe located in Toronto.

There are several concerns such as a large number of connections (approximately 360) to the high pressure (>175 psi / 1,200 kPa) main system as well as poor depth of cover issues. The large number of connections to the high-pressure main is a concern due to the known integrity issues associated with the degradation of the Field Applied Coatings and there being possible corrosion initiation locations. There are two known unrestrained compression couplings, nine restrained compression couplings, and three suspect valves that may have been tied into the main using compression couplings but not shown in EGI records. Cathodic Protection (CP) history for the past 20 years shows that over 15% of the readings taken were below the minimum requirements. Poor CP protection levels can lead to corrosion.

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 cm, with 77 survey locations measuring less than 60 cm of cover. Poor DOC can lead to increased third-party damages. See **Appendix A, Pg. 12** for additional detail on this investment.

NPS 12 Wilson Ave

The NPS 12 Wilson Ave project mitigates the risk from 8.3 km of early 1960's pipe (with some main segments as old as 1955) located in Toronto. This main supplies key customers including the Humber River Hospital.

There were issues with stray current-induced corrosion from nearby Toronto Transit Commission (TTC) rail systems resulting in significant leak repairs in 2017. There are three unrestrained compression couplings and four restrained compression couplings along this section of main. Another significant degradation factor is the poor field-applied coatings at service connections. There are approximately 250 service connections along this section of main, and there has been a history of leaks arising from these service connections. SMA input noted that when repairs were made, they observed very poor coating conditions; and in some cases, the coatings were no longer present leaving bare steel exposed. Curb Valve Tees have been damaged historically due to their location within the roadway and lack of cover. **Figure 5.2-58** shows corrosion pitting from TTC stray current. See **Appendix A, Pg. 10** for additional detail on this investment.

Figure 5.2-58: Corrosion Pitting from TTC Stray Current

Moulton Replacement Bare and Unprotected

The Moulton Replacement project is part of the Bare and Unprotected Replacement Program. There is 5.6 km of NPS 8 Intermediate Pressure (IP) bare steel main to be replaced with NPS 8 modern coated steel pipe between #1472 Hwy 3 to #2199 Hwy 3. These mains are more susceptible to leaks as they have not been cathodically protected since installation. See **Appendix A, Pg. 15** for additional detail on this investment.

Erin Township

Erin Township investment is replacing Aldyl-A PE pipe that is prone to slow crack growth (SCG) due to its known material and manufacturing flaws (large inner bore spherulitic structures and surface oxidation of the inner surface). The presence of stress intensification factors (for example, rock, service connections, and bend radius) can accelerate SCG and lead to loss of containment. Erin Township has seen several loss of containment Aldyl-A crack failures (see **Figure 5.2-59**), due to rocky soil where rocks create a stressor on the pipe that accelerates the cracking failures. This is a multi-year investment that will replace about 13.2 km of Aldyl-A mains and service pipe. See **Appendix A, Pg. 9** for additional detail on this investment.

Figure 5.2-59: Sample of Aldyl-A Pipe with Crack Failure

NPS 10 Glenridge Avenue

This project looks to replace approximately 8.7 km of mostly 1954 to 1960 vintage NPS 10 intermediate pressure (IP) pipe with sections of NPS 12 and NPS 8 spliced in over the years as repairs.

A 2019 Depth of Cover (DOC) survey found that 366 (33%) survey locations had less than 90 cm of cover, and 90 survey locations (8%) had DOC less than 60 cm, with one location found having exposed pipe due to creek erosion. Poor DOC 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. Unrestrained compression couplings have been a source of leaks due to ground settlement and increases 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 (see **Figure 5.2-60**). 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 as per an Integrity Assessment for suspect compression coupling 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. See **Appendix A, Pg. 11** for additional detail on this investment.

Figure 5.2-60: Exposed Pipe in Creek Crossing

5.2.3.6.3.4 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 Replacement 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.

5.2.3.6.3.5 Aerial Crossings

Through EGI's DIMP, condition surveys and assessments are planned in 2022 to get a full population understanding. From these condition assessments, further risk assessments will take place to understand the impacts from the degradation that has taken place. This may lead to specific replacements or a more systemic replacement mitigation approach.

5.2.3.6.4 DISTRIBUTION STEEL PIPE POST-1970 STRATEGIES

The maintenance strategy for post-1970 distribution steel pipe is consistent with pre- and including 1970 steel mains (see **Section 5.2.3.4.1**), where several condition inspection programs are in place, such as the Leak Survey and the Cathodic Protection Survey programs. For more detail on Common Distribution Strategies, see **Section 5.2.3.6.2**.

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 not be viable through the Emergency 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 2024 Rate Rebasing Customer Engagement results in which the majority of customers indicated that EGI should maintain current reliability levels.

5.2.3.6.5 DISTRIBUTION PLASTIC PIPE STRATEGIES

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 5.2.3.2** and lead to the following replacement/renewal strategies for distribution plastic pipe:

5.2.3.6.5.1 Vintage Plastic Aldyl A Replacement Program

In prior EGI Asset Management Plans, the reliability modelling for Aldyl A suggested a need for a proactive replacement program. However, as EGI performs continuous improvement of reliability models and asset understanding, the view towards Aldyl A has changed with the aid of introducing a Bayesian approach to integrate existing mechanical and statistical models that made EGI's reliability estimates more accurate. Overall, the results of the Bayesian model yield moderate failure projections for vintage plastic Aldyl A pipes in upcoming years (see **Figure 5.2-38** and **Figure 5.2-39**). Therefore, the approach for Vintage Plastic Aldyl A is to address leaks and other material faults on a reactive basis through the Emergency Replacement Program. There may be some localized replacement projects where stress intensification factors (like rocky soil) are accelerating degradation and increasing failures.

5.2.3.6.5.2 Intermediate Plastic Mains

Intermediate Plastic Mains will need to be further studied and understood through sampling and testing to determine if escalation of mitigation activities is warranted. Samples have been collected and sent for testing and analysis, and results should be available in 2023. The approach for Intermediate Plastic Mains is to address leaks and other material faults on a reactive basis through the Emergency Replacement Program.

5.2.3.6.5.3 AMP-fitting Replacement Program (Copper Risers)

Based on the Asset Health Review operating process 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 proactive 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 AMP-fitting Replacement Program plans to replace increasing numbers of copper risers per year increasing to 20,000 by 2027. **Figure 5.2-61** demonstrates the number of expected leaks discovered on a yearly basis.

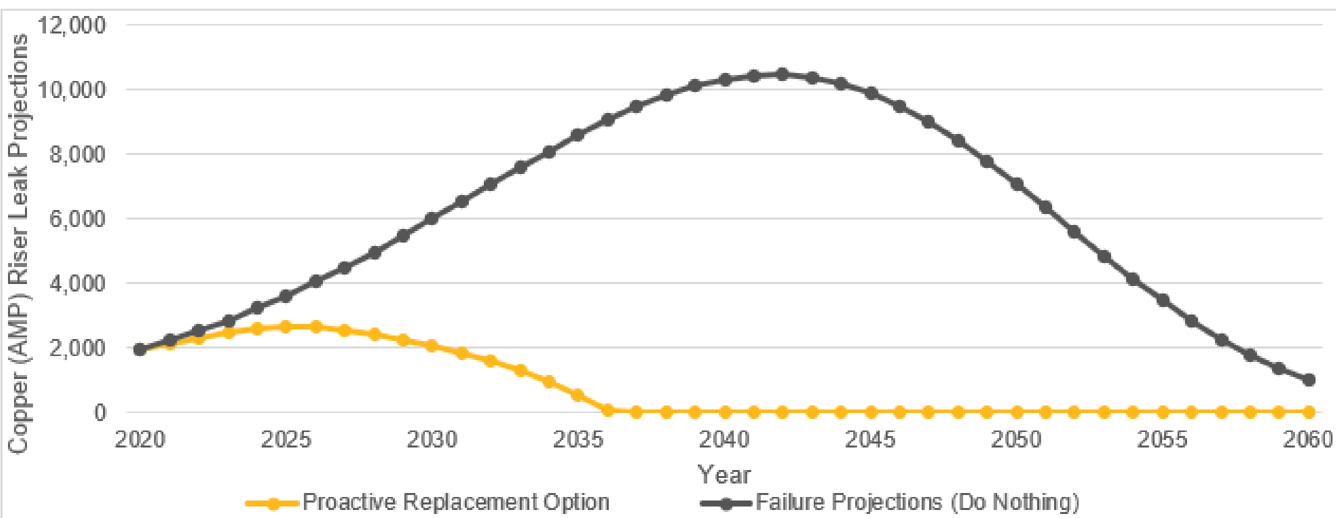


Figure 5.2-61: Copper (AMP-Fittings) Riser Leak Projection – Reactive vs. Proactive Strategy

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 noncompliant riser assets. Risers continue to be monitored under the Leak Survey and Corrosion Survey programs.

5.2.3.7 Distribution Pipe Capital Expenditure Summary

The total average capital spend is forecast to be $360M (EGI) as summarized in **Table 5.2.3-4**. The Distribution Pipe capital is further summarized as part of EGI's total 10-year capital plan in **Section 6**. See **Appendix B – IRP** for the status of the outcomes of the IRP assessment process, including the binary screen and the status evaluation of IRPAs.

The Distribution Pipe Capital Expenses increase rapidly from 2027 onward due to the start of the Vintage Steel Replacement Program (see **Section 5.2.3.6.3.2**).

Table 5.2.3-4: Distribution Pipe Capital Summary ($ Millions) – EGI[11]

Asset Class Strategy/Investment Name	Program/Project Name	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-Year Forecast
TIMP Retrofits and Digs	Integrity	21.2M	21.8M	22.4M	20.7M	22.1M	2.8M	2.7M	2.8M	2.8M	2.7M	**122.2M**
Inspection Program Integrity Retrofits and Digs	Integrity	51.6M	51.4M	27.0M	42.0M	26.2M	21.9M	21.7M	22.5M	22.2M	21.6M	**308.0M**
Depth of Cover Program	Integrity	7.5M	5.1M	5.2M	4.2M	4.5M	3.0M	1.7M	0.7M	0.7M	0.7M	**33.2M**
Depth of Cover Program	Main Replacement	-	-	0.0M	0.4M	0.5M	0.5M	0.2M	-	-	-	**1.6M**
Class Location Program	Class Location	3.5M	2.6M	2.6M	6.5M	6.9M	6.9M	6.8M	7.1M	7.0M	6.8M	**56.7M**
Corrosion Prevention Program	Corrosion	11.6M	11.5M	10.6M	10.2M	10.3M	10.4M	10.8M	10.9M	11.0M	11.1M	**108.6M**
Emergency Replacement Program	Main Replacement	3.7M	3.9M	4.0M	4.1M	4.5M	4.5M	4.6M	4.8M	4.8M	4.8M	**43.6M**
General Replacement Program	Main Replacement	28.7M	5.4M	14.8M	14.2M	32.9M	34.5M	19.2M	19.9M	38.4M	17.4M	**225.4M**
Service Replacement Program	Service Relay	28.2M	29.6M	30.5M	31.4M	34.1M	34.5M	34.9M	36.7M	37.1M	36.7M	**333.7M**
Relocation Program	Relocations	48.6M	42.9M	43.7M	44.4M	48.6M	56.4M	46.2M	47.8M	47.3M	45.9M	**471.7M**
Bare and Unprotected Program	Main Replacement	16.1M	12.6M	0.1M	-	-	-	-	-	-	-	**28.7M**
Vintage Steel Replacement Program	Main Replacement	19.0M	41.7M	33.8M	19.1M	54.4M	94.0M	146.6M	208.7M	270.7M	320.5M	**1208.4M**
St. Laurent Phase 3 - North/South (NPS12/16 Steel)	Main Replacement	1.2M	56.1M	2.0M	-	-	-	-	-	-	-	**59.4M**

[11] Includes overhead allocation

Asset Class Strategy/Investment Name	Program/Project Name	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-Year Forecast
St. Laurent Phase 4 - East/West (NPS12 Steel)		-	-	23.5M	0.7M	-	-	-	-	-	-	**24.2M**
Port Stanley Line		0.6M	18.5M	-	-	-	-	-	-	-	-	**19.1M**
NPS 12 Martin Grove Rd		-	-	0.5M	22.6M	0.8M	-	-	-	-	-	**24.0M**
NPS 12 Wilson Ave		-	36.1M	53.8M	1.2M	0.0M	-	-	-	-	-	**91.2M**
Moulton Replacement Bare and Unprotected		-	0.8M	17.8M	-	-	-	-	-	-	-	**18.5M**
Erin Township		3.0M	3.0M	2.8M	2.9M	-	-	-	-	-	-	**11.7M**
NPS 10 Glenridge Avenue		-	0.4M	7.8M	7.1M	-	-	-	-	-	-	**15.3M**
Copper Services Replacement Program	Service Relay	2.3M	2.4M	0.9M	-	-	-	-	-	-	-	**5.7M**
AMP Fitting Replacement Program		15.2M	22.4M	29.5M	36.8M	46.6M	47.1M	47.7M	50.2M	50.6M	50.1M	**396.2M**
Total		**261.9M**	**368.3M**	**333.3M**	**268.7M**	**292.3M**	**316.4M**	**343.3M**	**412.1M**	**492.5M**	**518.2M**	**3606.9M**

5.2.4 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 overpressure 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 36,000 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. Renewable Natural Gas (RNG) and Compressed Natural Gas (CNG) customer stations which support EGI's low-carbon strategy are included in the Distribution Stations asset class. Distribution Stations are organized into three subclasses based on function:

- **Stations with Auxiliary Equipment** 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 or header in the downstream system.
- **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, Massachusetts where a distribution system was overpressured. EGI took some immediate measures to review procedures and records and ensure that sense lines were inside the perimeter of regulation stations. EGI has evaluated the risk in each of these installations and will target the stations that require additional layers of protection to bring the risk to broadly tolerable or as low as reasonably practicable.

With more than 36,000 stations of varying degrees of complexity and criticality, EGI is developing analytics to establish age, condition and risk to develop the associated maintenance and replacement strategies.

As EGI continues to review and standardize operating standards 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 large Stations with Auxiliary Equipment stations to ensure compliance with applicable codes and standards.

Figure 5.2-62 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 5.2-62** is for illustrative purposes only and is not meant to display all possible configurations.

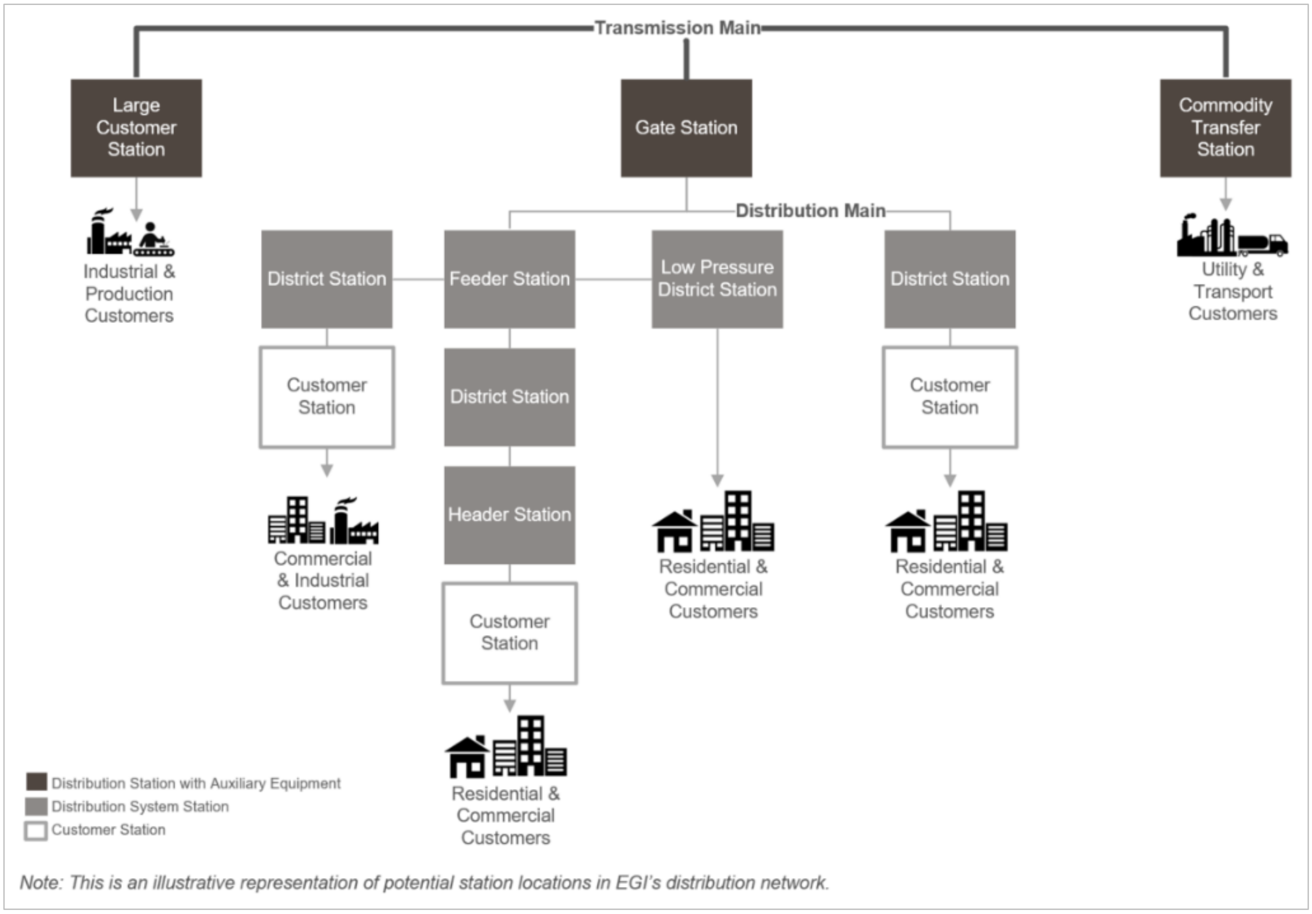


Figure 5.2-62: Station Hierarchy by Type

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 5.2-63 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, filtration to remove contaminants (where applicable), 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.

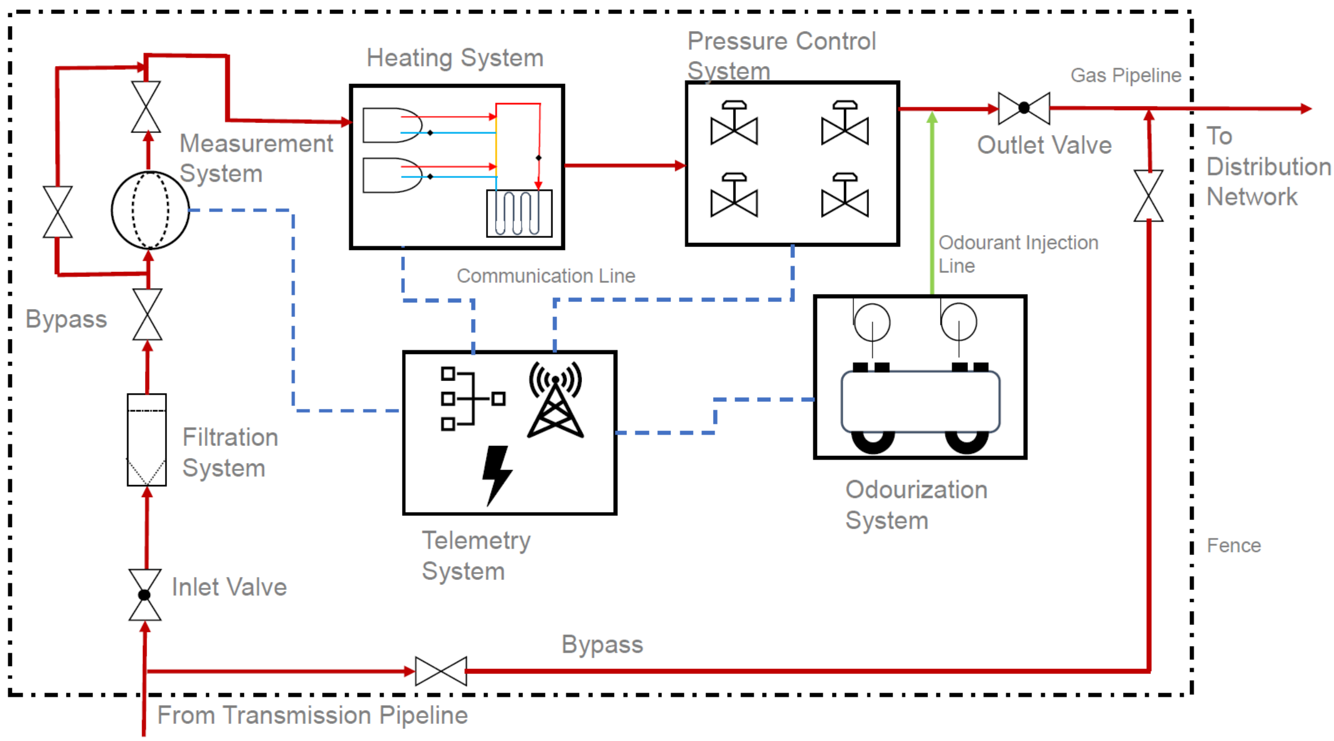


Figure 5.2-63: Station Components

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 overpressure protection in the event the operator regulator fails. Pressure regulators maintain a desired outlet pressure while providing the required flow to satisfy a variable downstream demand and can be direct-operated or pilot-operated. Relief valves provide an audible and odour 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 utilized to remove particles of dirt and/or liquids 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 retain heat or for noise attenuation. Protection of the piping system consists of underground corrosion control systems and aboveground 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 subcomponents: 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 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 as well as protection against frost heave of the station piping.

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
- Pressure recorders
- Gas monitors
- Communications devices and antenna towers
- Power supply, Uninterruptible 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 is introduced automatically at all stations at the entry point to the gas distribution network. Subcomponents of the odourization system include:

- Odourant tank
- Odourant pumps
- Injection point with sight glass
- Odourant containment
- Meters or orifice plates, 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 5.2.5.5.** 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 and heating system temperature requirements) 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, foundations, property lighting, security systems, piping supports and barriers, water management systems such as culverts and ditches and general property.

5.2.4.1 Distribution Stations Inventory

Table 5.2.4-1 lists the inventory details for the Distribution Stations asset class.

Table 5.2.4-1: Distribution Stations Asset Class Inventory

Asset Subclass	EGD Rate Zone[12]	Union Rate Zones[13]
Stations with Auxiliary Equipment	171 stations	373 stations
Distribution System Stations	5,007 stations	2,345 stations
Customer Stations[14]	12,936 stations	15,314 stations

Note: The inventory for meters and regulators (discussed in **Section 5.2.5**) also includes meters and regulators located at Customer Stations and included in the inventory shown in **Table 5.2.4-1**.

[12] EGD rate zone inventory as of September 4, 2021.
[13] Union rate zones inventory as of May 27, 2021.
[14] CNG stations included in Customer Stations inventory class as of November 17, 2021.

5.2.4.2 Distribution Stations Condition and Strategy Overview

Table 5.2.4-2 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 5.2.4-3**.	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 have been found to have the following deficiencies: obsolescence, performance issues and nonstandard configurations.	Risks identified for Stations with Auxiliary Equipment: **Employee and Contractor Health and Safety Risk / Public Health and Safety Risk**: Impact on surrounding population in the event of loss of containment **Financial Risk**: Commodity loss, repair costs and regulatory penalties **Operational Risk**: Loss of service to customers **Environmental Risk:** Noise, spills and GHG emissions	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 Capital Upgrades Program • Facilities Integrity Management Program • Stations Painting Program • Renewable Natural Gas (RNG) Strategy
Distribution System Stations	See **Table 5.2.4-5**.	Distribution System Stations assets are inspected through field condition survey assessments to identify the type of regulators, belowground installations, nonconforming configurations and vintage/obsolete components, contributing to a higher potential of failures and operational issues.	Risks identified for Distribution System Stations and Customer Stations: **Employee and Contractor Health and Safety Risk / Public Health and Safety Risk**: Public impact, threat to overpressuring 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 • Vaulted Stations Replacement Program • Stations Painting Program • Stations Capital Upgrades Program
Customer Stations	See **Table 5.2.4-7**.	Customer Stations assets are inspected through field condition survey assessments to identify the type of regulators, belowground installations, nonconforming configurations and vintage/obsolete components, contributing to a higher potential of failures and operational issues.			The replacement / renewal strategy for Customer Stations includes: • Customer Station Replacement Program • Inside Regulator Room Program • Pressure Factor Metering Rebuild Program • Compressed Natural Gas (CNG) Strategy • Stations Painting Program • Stations Capital Upgrade Program

5.2.4.3 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 types of 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 filters, 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.
- **Large Customer Stations** refer to a commercial or industrial station where the downstream system served is a single service.
- **Gas Producer Stations** are stations fed from an Ontario Producer's facility and feed into a company pipeline. This includes Renewable Natural Gas (RNG) injection stations.

The majority of station sites have aboveground components, with some piping and operating equipment located belowground. All gate and transmission, feeder, large customer station, and gas producer sites are located on EGI-owned or leased property and most 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 in the form of more frequent on-site inspections. 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 5.2.4-3 represents the age of the various systems components at all station sites for this subclass. 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 5.2.4-3: Stations with Auxiliary Equipment Station Component Age

Station Component	Average Asset Age (Years)		Maximum Asset Age (Years)	
	EGD Rate Zone	Union Rate Zones	EGD Rate Zone	Union Rate Zones
Pressure Control	12	20	61	63
Odourization	12	12	26	49
Heating System	11	18	26	63
Telemetry	8	15	36	38

Table 5.2.4-3 shows EGD and Union rate zones have differences in 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.

5.2.4.3.1 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. Inspection results and trouble call history are recorded and analyzed to understand asset performance, condition and health.

EGI has enhanced the Facilities Integrity Management Program (FIMP), which provides the framework to identify threats, monitor facility conditions and manage integrity data to ensure that the pipeline facilities system is suitable for continued safe and reliable service and to comply with applicable regulations. FIMP applies to stations that meet the following criteria:

- Facilities connected to pipelines that are part of the GDS Transmission Integrity Management Program (TIMP), including STO, System, Customer Stations, and valve sites.
- 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 (including facilities connecting EGI with a GDS affiliate, and facilities receiving RNG or hydrogen for blending into the pipeline system).
- A station which contains any of the following equipment:
  - Glycol-based heating system (heat exchanger or line heater)
  - Filtration of one of the following types, where the filter is deemed to be a pressure vessel as per ASME Boiler and Pressure Vessel Code:
    - Liquid Removal (filter separator, separator, scrubber and coalescer)
    - Large Dry Gas Filters
  - Odourization

5.2.4.3.2 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 5.2.4-4.**

Table 5.2.4-4: 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 Electrical Safety Authority (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 or odourant.
Function	• The asset is unable to deliver the required demand (i.e., insufficient gas supply, heating requirements or overworked components) 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 overpressure situations.
Operability	• Operating performance and reliability interventions contribute to increased unplanned maintenance costs and potential safety concerns.
Maintainability	• 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. • 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 overpressure 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.

Issue	Description
	• 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 and RTU
- The performance of the asset, such as known operational problems
- Asset history and the evaluation of failure events
- Subject Matter Advisor (SMA) input

To better understand asset condition, the FIMP will provide direct assessment data as described in **Section 5.2.4.3.1**.

5.2.4.3.3 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) that are observed for this asset subclass:

- **Loss of Pressure Control**: Pressure control failures could cause an overpressure or under-pressure scenario.
    - **Overpressure Event**: Stations are the delineation between different operating network pressures. Failures causing overpressure 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. Overpressure could lead to component failure in the downstream network, overstressing 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 overpressure 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, and other customers 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 overpressure protection to reduce the likelihood of a pressure control failure.
- **Loss of Measurement System Function:** Measurement equipment can be used to measure customer and system gas flow rates, and accurately inject odourant into the pipeline. Loss of measurement functionality could lead to inaccuracy of gas measurement, inaccurate billings of commodity transfer which could result in volume billings or purchase disputes and improper odourant levels (undetectable gas leaks).
- **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 increase 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, (1) frost heave or (2) pressure control failure due to the freezing of station components. Frost heave occurs when the gas is cooled due to the pressure reduction and causes an upward swelling of soil around public or private property near the gas main. Freezing of station components such as creating large ice buildup around valves can prevent operation if gas isolation is required. This could result in the loss of pressure control and potentially lead to an overpressure or under-pressure situation. 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 longer emergency 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, greater patrols, and potential impacts to station equipment dependent on Telemetry components. 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 could impact the odourant, telemetry, auxiliary systems (i.e., fire suppression), 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, demand on the system 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 health and 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 loss of service to customers. Finally, there can be environmental risk through the unplanned release of GHG’s in the event of a component malfunction.

5.2.4.4 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. Distribution System Station components consist of piping, meters, regulators, valves, and in some cases, limited pressure monitoring. Distribution 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, fenced in, located above ground without an enclosure or buried below-grade in a vault.
- **Multi-unit building (MUB):** Multi-unit residential buildings which have a mix of residential customers with in-suite appliances, commercial customers, and/or central boilers. The supply of gas is through vertical piping that runs through a chase or outside the building, and the distribution of gas may involve a garage header with sub-metering.

These are sometimes referred to as garage headers or vertical subdivisions. Garage headers have meters in a meter closets or branches in a basement parking garage. Vertical subdivisions include vertical runs to meter closets or individual units.

Distribution System Stations consist of mechanical components with shorter lifespans relative to other gas-carrying assets (see **Table 5.2.4-5**).

Table 5.2.4-5: Distribution System Stations Station Component Age

Distribution System Station Rate Zone	Average Asset Age (Years)	Maximum Asset Age (Years)
EGD Rate Zone	17	57
Union Rate Zones	21	70

The rate zones have differences in the average asset age and the maximum age of the current population. This is expected due to the different design standards and maintenance strategies employed throughout the history of the legacy companies. Integration activities are ongoing to harmonize best practices for engineering design and operating standards in the rate zones.

In addition to the average age of assets, there are variations in how the replacement of components have been captured in record systems. In some cases, the age of the asset reflects the last intervention to replace a component; and in other cases, the age of the asset reflects its initial installation date even if some components have been replaced since that time.

Based on information in the appropriate systems of record, **Figure 5.2-64** and **Figure 5.2-65** reflect the age of the Distribution System Stations in the EGD and Union rate zones respectively. Two outliers in the number of stations in the Union rate zone at 19 and 30 years can be attributed to the integration of legacy asset information systems. This reflects the date of the acquisition of the assets – not the installation date. Work continues to understand the demographics of station assets and their component systems.

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.

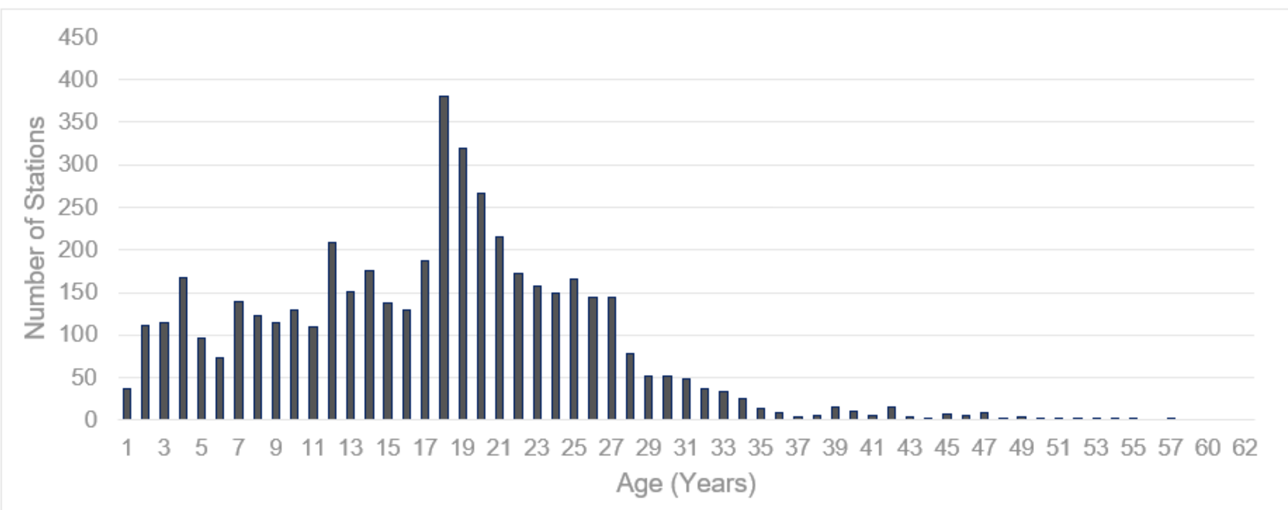


Figure 5.2-64: Distribution System Stations – Age Demographics (EGD Rate Zone)

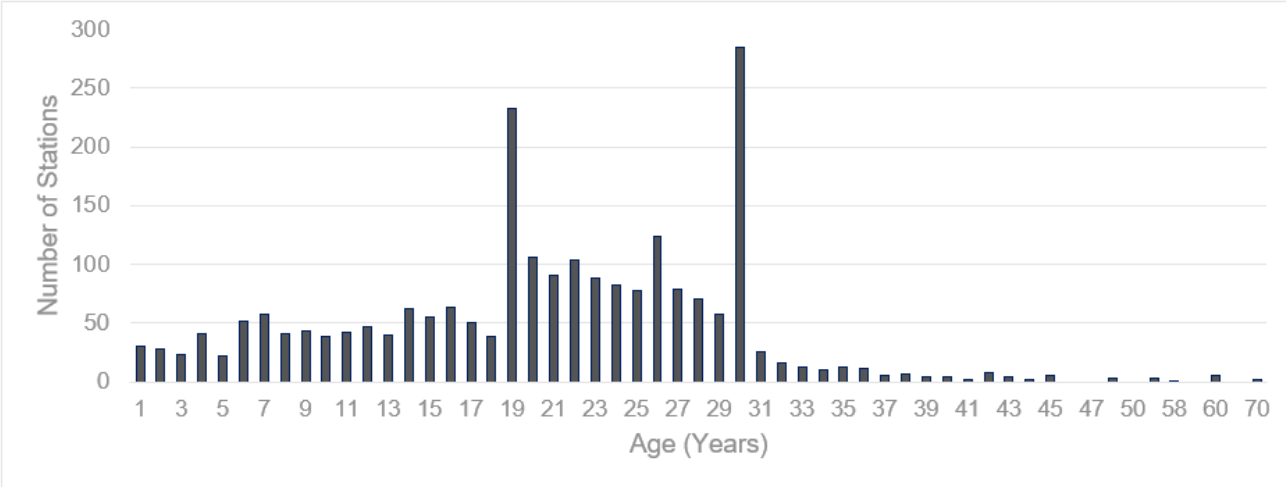


Figure 5.2-65: Distribution System Stations – Age Demographics (Union Rate Zones)

Distribution System Stations are generally installed either above ground or belowground in a vault (see **Figure 5.2-66**) and typically installed on public rights-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. Belowground 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 accelerated pipe coating degradation which can lead to corrosion. Flooding could impact the mechanical operation of the pressure control and valve systems.

Figure 5.2-66: Examples of Distribution System Stations

5.2.4.4.1 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 5.2.4.5**).

The Distribution Integrity Management Program (DIMP) used statistical reliability analysis and modelling of the EGD stations historical failure data to make predictions about the life of distribution system station assets in a previous version of the Asset Management Plan[15]. In order to support an integrated approach for assessing asset health for EGI stations and accounting for differences in design, construction practices, maintenance, and availability of data for both legacy companies, the most recent Asset Health Review (AHR) leveraged available condition related data through field inspection programs to evaluate the asset health.

Since Distribution Stations are predominately above-grade assets and inspected regularly through maintenance programs, the DIMP leveraged this opportunity to collect condition-related information during inspections. The condition information is comprised of a series of visual evaluations as well as some functional operational assessments which have been determined by SMAs to be an early indicator of functional failure of a specific station subsystem.

The Field Assessment Survey Tool (FAST) was used to capture condition information at EGD stations, while the 2018 Station Painting Survey that recorded corrosion severity was used for Union stations. To better understand how the condition of each subsystem aggregates to the station level, the condition of the four major subsystems was assessed on various parameters that contribute to the different failure modes. A scoring methodology was designed to differentiate between the ranking of each subsystem based on their criticality prior to rolling up the subsystem's condition. The roll-up methodology is considered as an indicator for the overall station condition. The results of this analysis can be seen in **Section 5.2.4.4.2**.

On-site condition assessments are conducted to assess, classify and further understand condition details that cannot be determined through data analysis alone. **Table 5.2.4-6** outlines the specific condition evaluation criteria used to assess station components. These assessments inform the priority of individual stations for station replacement programs.

Table 5.2.4-6: Evaluation Criteria for Station Components

Station Component	Condition Evaluation
Pressure Control	• Correct operating parameters for each regulator (i.e., outlet pressure matches the correct set point) • Ability to lock up under zero flow condition • Appropriate response to changes in outlet pressures and flows • Overpressure protection device operating at its specified set point and adequate capacity • Obsolete equipment and/or parts unavailable • Improper/nonstandard configuration
Station Valves	• Difficulty with operating and moving freely • Valve leaking to atmosphere • Valve damaged or inaccessible • Valve not sealing completely and inability to isolate gas flow
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

[15] EB-2020-0181, Exhibit C, Tab 2, Schedule 1

Other factors to be assessed include:

- Station capacity verification (to ensure the reliability of supply to EGI's growing customer base)
- Compliance with relevant codes and standards

5.2.4.4.2 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. As of March 2021, over 8,000 station condition assessments were collected through FAST in the EGD rate zone representing approximately half of the total population, and 2,421 were Distribution System Stations.

Utilizing the aggregated ranking of each sub-system based on their criticality to the station level, **Figure 5.2-67** helps to illustrate the findings of the condition assessments and provides insight into the mitigation levels required for the current replacement program. Note that the section of the chart marked as Unknown reflects the assets that were not part of the station condition assessments completed as of March 2021.

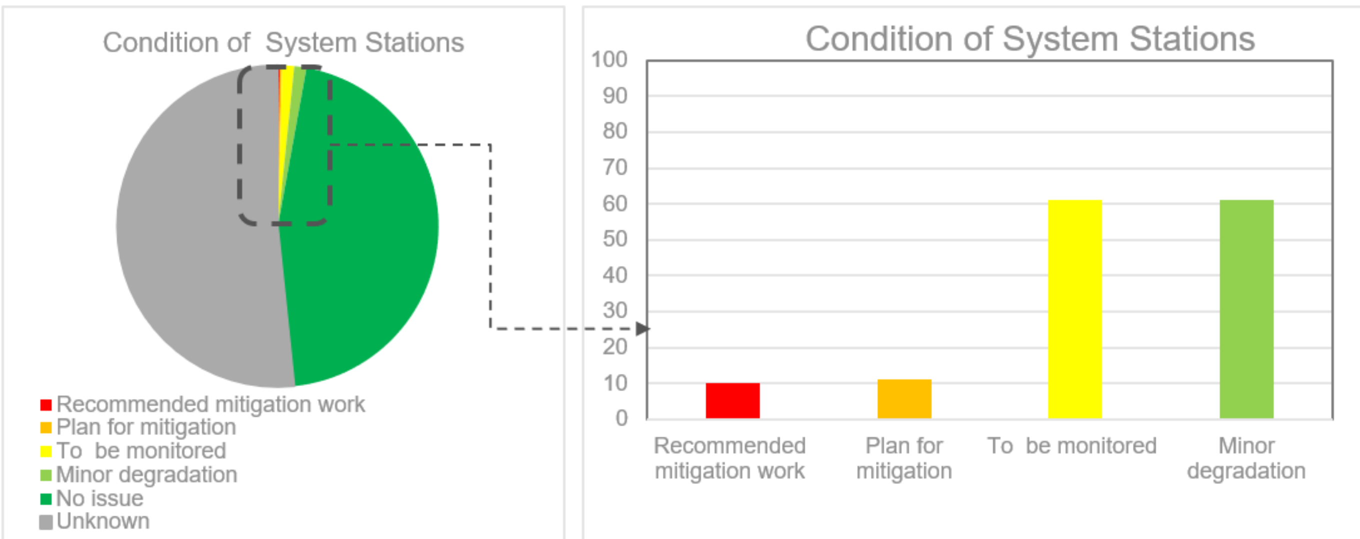


Figure 5.2-67: Distribution System Stations Condition Aggregate – EGD Rate Zone

Figure 5.2-67 reveals that Distribution System Stations are in relatively good condition with a constantly low-component failure rate indicating the historical replacement and renewal programs are effective. At this time, Union rate zones' assets have a different assessment methodology, that was described above, within the Asset Health Review (AHR) program. A plan is being developed to integrate both legacy assessment methodologies into a common approach.

In the Union rate zones, a Station Painting Survey was initiated in 2018 to collect corrosion assessments at Union Distribution System Stations. The inspections focused on the corrosion defects on station subcomponents (mainly piping subsystem). Corrosion degradation was evaluated using the criteria defined in ASTM D 160-01 standard. Approximately 5,000 stations identified by Union SMAs as critical or exposed to higher risk of degradation were selected for the assessments. Since 2018, approximately 1,480 stations with some corrosion indications have received mitigation work mostly related to corrosion removal and repainting activities; and there is a program to continue with the balance of the population.

On-site condition assessments continue to be collected on an ongoing basis to thoroughly understand the condition of distribution system station assets for the rate zones. 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 overpressure events.

Another example of issues from field reviews of distribution system station sites have found nonconforming 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.

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 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 5.2-68**. Ice buildup is visible on the downstream components and the station assembly is misaligned due to heaving.

Figure 5.2-68: The Joule-Thomson Effect on a District Station

5.2.4.4.3 RISK AND OPPORTUNITY

The risks identified for Distribution System Stations are operational risk, financial risk, employee and contractor health and safety risk and public health and safety risk, which may lead to the following consequences:

- Public impact, threat to overpressuring 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 (see **Section 5.2.4.5**). Risks are dependent on station design and location:

- **Overpressure Event**: In an overpressure event, the downstream network is operating above the designed maximum pressure. In addition to the risks discussed in **Section 5.2.4.3.3**, 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 defence against potential piping overpressure inside the customer's premises.
- **Loss of Pressure Control (Lock Up)**: A regulator fails to lock 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 overpressure 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 overpressure 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 overpressure 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, overpressure 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. For risks associated with under-pressure events, see **Section 5.2.4.3.3**.
- **Valve System Malfunction**: A valve malfunctions when it no longer provides isolation of the gas as intended. For risks associated with valve system malfunctions, see **Section 5.2.4.3.3**.

Additional issues that were considered in the risk assessments were obsolete regulators, single-run stations and stations with noncompliance 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. Some stations are capable of a manual bypass as a mitigation measure to reduce the potential for a disruption of service. Exposure to under-pressure risk is greater in the absence of a standby run. Noncompliant stations are typically locations where surrounding developments have encroached within the hazardous zone, causing clearance concerns.

Distribution System Stations that were installed below grade in a vault were evaluated to consider risks such as additional maintenance requirements, leaks within a confined space, increased replacement cost and potential for worker injury. It is expected that the projected reliability for these belowground assets will be lower and will degrade faster than other aboveground assets.

5.2.4.5 Customer Stations

Customer Stations reduce upstream pressure and deliver gas to a downstream customer with a total connected load greater than 12 m³/h 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 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, steel mills, chemical plants, smelters and other process-based industrial plants. Compressed Natural Gas (CNG) stations are included in the Customer Stations subclass.

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 5.2.4.3**).

Table 5.2.4-7: Customer Stations Station Component Age

Rate Zone(s)	Average Asset Age (Years)	Maximum Asset Age (Years)
EGD	16	62
Union	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. In addition to the average age of assets, there are variations in how the replacement of components have been captured in systems. In some cases, the age of the asset reflects the last intervention to replace a component and in other cases the age of the asset reflects its initial installation date, even if some components have been replaced since that time.

Based on information in the appropriate systems of record, **Figure 5.2-69** and **Figure 5.2-70** reflect the age of the Customer Stations in the EGD and Union rate zones respectively. An outlier in the number of stations at 30 years can be attributed to the integration of legacy asset information systems; the date reflects the date of acquisition – not the date of installation. Work continues to understand the demographics of station assets and their component systems.

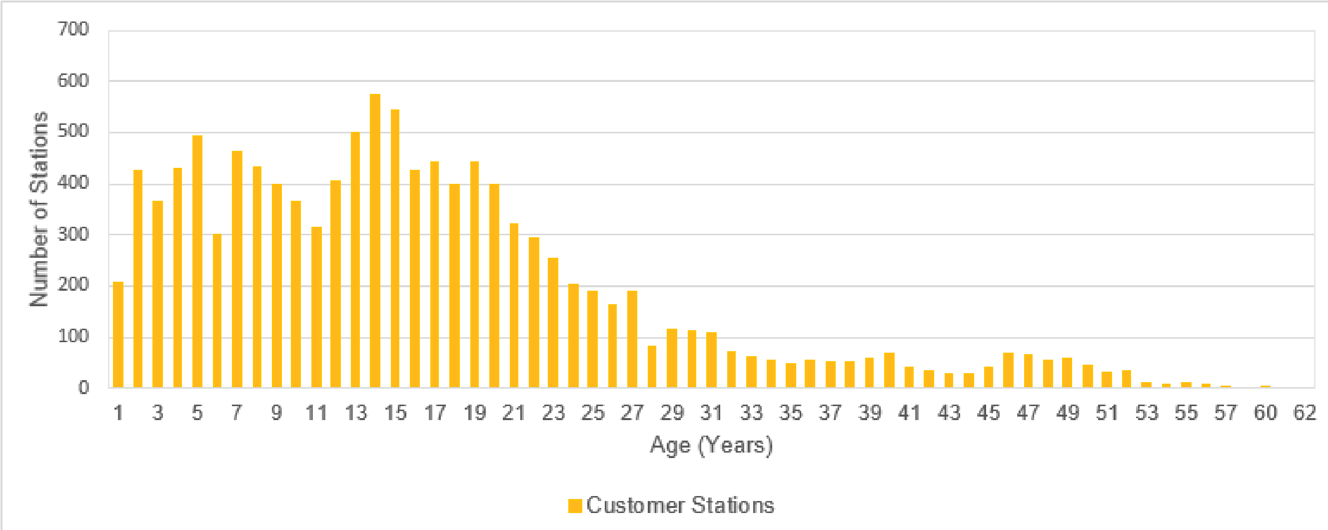


Figure 5.2-69: Customer Stations – Age Demographics (EGD Rate Zone)

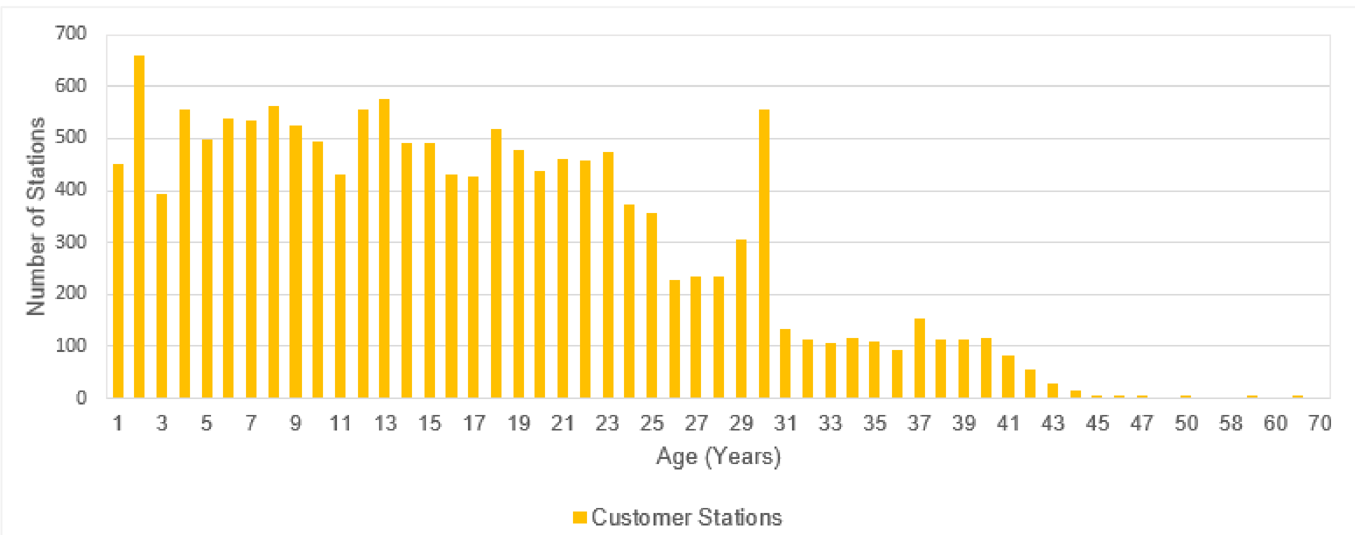


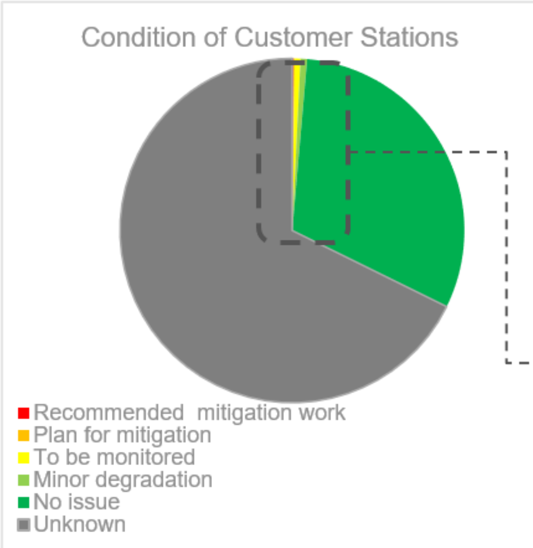
Figure 5.2-70: Customer Stations – Age Demographics (Union Rate Zones)

5.2.4.5.1 CONDITION METHODOLOGY

The condition methodology for Customer Stations is the same as for Distribution System Stations (see **Section 5.2.4.4.1**).

5.2.4.5.2 CONDITION FINDINGS

Customer Stations experience failures similar to Distribution System Stations (see **Section 5.2.4.4.1**). The condition findings for the EGD rate zone are similar to what was described in **Section 5.2.4.4.2**. Of the 8,000 assessments, 4,098 were Customer Stations and from the aggregated ranking of each sub-system based on their criticality to the station level, **Figure 5.2-71** helps to illustrate the findings of the condition assessments and provides insight into the mitigation levels required for the current replacement program. Note that the assets reflected as Unknown were not part of this initial condition assessment.



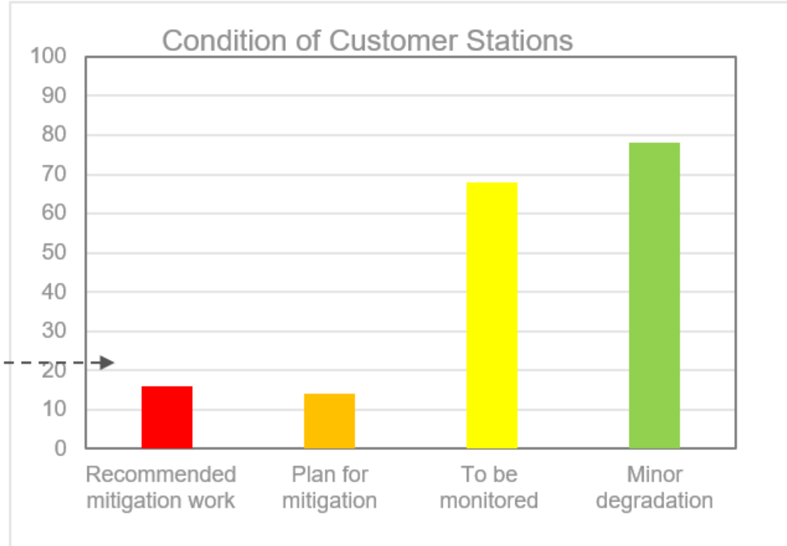


Figure 5.2-71: Customer Stations: Projected Failure Events

5.2.4.5.3 RISK AND OPPORTUNITY

The risks identified for the Customer Stations asset class are similar to risks for Distribution System Stations (see **Section 5.2.4.4.3**) The hazards identified include:

- Overpressure of non-boot style regulators
- Nonconforming 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 5.2.4.4.3**.

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.

Inside Regulator Relocation risks

EGI has performed a survey to identify inside regulators at Customer Stations which may experience a higher leak rate from higher-operating pressure piping compared to pipes operating at lower pressures (for same hole size). Indoor regulators use higher-operating pressure pipe indoors; potential leaks may be able to reach their lower flammability limit (LFL) faster. Depending on leak rate, building ventilation, and room size, it is possible for an indoor gas leak to build up to its LFL, leading to possible ignition and resulting in an explosion.

5.2.4.6 Distribution Stations Strategy Outcomes

5.2.4.6.1 STATIONS WITH AUXILIARY EQUIPMENT STRATEGIES

5.2.4.6.1.1 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 2024

Rate Rebasing Customer Engagement results in which customers were 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).

Major Stations with Auxiliary Equipment investments include:

Lisgar Gate Station Risk Mitigation

The Lisgar Gate Station is located in a highly populated area in the City of Mississauga. The station is situated in an urban setting and is surrounded by residential buildings, a commercial plaza, and a place of worship. The station has multiple feeds (two transmission lines and one extra high-pressure [XHP] Canada Energy Regulator (CER) line and various outlets to local distribution networks. In the event of a major incident, consequences would be significant given the close proximity of houses and buildings to the station. A recent inspection has identified degradation of the heating system and one of the buildings has structural degradation. Renewal of degraded assets and potential relocation of portions of the station to the Parkway East Station will be necessary to support risk reduction and improve long-term reliability of the site. See **Appendix A, Pg. 21** for additional detail on this investment.

Crowland Station

The Crowland Station has obsolescence issues related to the Remote Terminal Unit (RTU) and electrical system and does not have backup power generation. Mitigation of these issues has been limited due to the location of the RTU building that is located in an electrical hazardous area. In addition, there is an opportunity to better utilize the Crowland Storage Pool by abandoning the station's station's 1970 vintage compressor and other aging assets, and rebuilding the distribution components with new regulation, measurement, and remote capabilities. Doing so will eliminate the requirement to staff the site during operation of the compressor while improving operational control during peak hours, thereby reducing the cost of purchasing high-priced gas on the spot market during the coldest days. See **Appendix A, Pg. 18** for additional detail on this investment.

5.2.4.6.1.2 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.

5.2.4.6.1.3 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, including providing the appropriate containment systems to minimize the impacts of an event.

5.2.4.6.1.4 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.

5.2.4.6.1.5 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 and routers
- 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

5.2.4.6.1.6 Facilities Integrity Management Program

FIMP assesses stations against threats that are listed in the EGI Hazard and Risk Common Register to identify susceptibility to the risks and determine mitigation strategies for individual sites, ensuring that risk is managed to the lowest practical levels. The strategy for the FIMP is to perform inspections with approved technologies used at EGI or other utilities for similar asset types. These inspections will assess the condition of existing station assets and will detect any concerns or issues to help determine the likelihood and consequence of failure of individual components and evaluate the risk. This strategy will allow for targeted replacement and will extend the useful life of assets by identifying condition issues prior to the occurrence of an incident. 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.

5.2.4.6.1.7 Renewable Natural Gas Station Strategy

RNG is a renewable source of energy generated by methane emissions from landfills and other waste sources. It can be captured, cleaned and blended into EGI's natural gas network and used for residential and commercial energy needs as well as transportation fuel. The RNG strategy supports customer stations that allow RNG producers to inject their lower-carbon fuel into the distribution system. RNG opportunities help achieve lower emissions and make productive and economic use of landfill and other organic sources. This capital expenditures in this AMP do not include costs for RNG, refer to Exhibit 2, Tab 5, Schedule 2 for the associated capital expenditures.

5.2.4.6.2 DISTRIBUTION STATIONS STRATEGIES

5.2.4.6.2.1 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:

- Belowground boxes
- Boot-style regulators
- Capacity issues
- Poor performance and poor condition
- Low-pressure control
- Obsolete components

Condition assessment reviews, SMA consultation and risk assessments are all used to prioritize stations for replacement. Since these stations are small and prefabricated 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 belowground.

The replacement pace for Distribution System Stations is based on history and maintains the reliability of the station population at a relatively consistent level within the 10-year plan. This aligns with feedback from the 2024 Rate Rebasing Customer Engagement as the majority of customers indicated a preference for EGI to assess the long term health of the system and to spread out costs over time (even if that means higher rates now).

5.2.4.6.2.2 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, nonstandard configurations and other issues identified in **Section 5.2.4.4.2**. 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. Header Stations are called System Stations in the Union rate zone and the strategy is included in the Distribution System Station Replacement Strategy (see **Section 5.2.4.6.2.1)**.

5.2.4.6.2.3 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. 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.

5.2.4.6.3 CUSTOMER STATIONS STRATEGIES

5.2.4.6.3.1 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 nonstandard 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 nonconforming configurations and minimize impacts to businesses and customers.

Condition assessment reviews, SMA consultation and risk assessments are used to prioritize stations for replacement. Since these stations are small and prefabricated off site, the scope of the investment includes replacing the entire station (pressure control, overpressure protection, valves) and as necessary, associated inlet/outlet piping belowground. 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 workers' health and safety to ensure maximum risk reduction and benefit.

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.

5.2.4.6.3.2 Inside 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. Across the Union rate zones, services that have inside regulators are being relocated outside of the building envelope where appropriate. Development of the scope and pacing of the project is ongoing and the highest risk installations are being prioritized for remediation.

5.2.4.6.3.3 PFM Rebuild Program

A subset of the Customer Stations population are called Pressure Factor Metering (PFM) stations. Many PFMs in the Union rate zones do not have built-in bypasses or provisions for a bypass which does not allow for standard operation inspections to be performed. These installations are operationally inspected every five years and during this period the total population will be assessed. Those that require a rebuild will be identified within the next five-year window. The mitigation of this configuration will be completed before the next inspection within the following five-year window.

5.2.4.6.3.4 CNG Station Strategy

The new CNG Station Strategy involves the acquisition of new large and mobile Natural Gas Transportation (NGT) and small Vehicle Refueling Appliances (VRA) station customers and the installation of the necessary fueling equipment. The timing and scope for new NGT assets are based on the likelihood of contract confirmation and historical station installations of similar size and scope.

The renewal and upgrade of existing stations to ensure the continued safe, efficient, and reliable operations of all NGT stations. This approach includes the following activities:

- Small NGT Stations (VRAs)
- Proactively replacing/rebuilding VRA compressors (~35 units per year)
- Proactively replacing/rebuilding remote panels (~33 units per year)
- Reactively replacing gas detectors as needed (~5 units per year)
- Large, mobile and Utility NGT stations
- Maintaining a proactive compressor block rebuild program (~3 to 4 units per year).
- Reactively remediating station components due to findings from on-site condition assessments
- Proactively replacing manual shutoff valves with automatic models when identified for replacement

5.2.4.6.4 COMMON DISTRIBUTIONS STATIONS STRATEGIES

5.2.4.6.4.1 Stations Capital Upgrades Program

This program addresses various risk remediation activities including replacement of obsolete equipment, addressing regulator freeze-offs, remediating stations that have experienced frost heave, and investing in unforeseen issues at stations that require immediate remedy.

5.2.4.6.4.2 Distribution Stations Painting Program

This program is 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 or has a higher risk of corrosion due to roadside salt exposure or are physically shaded. High-performance paint reduces the probability of leaks and piping/equipment failure due to significant corrosion. This program is specific to the Union rate zones only.

5.2.4.7 Distribution Stations Capital Expenditure Summary

The total average capital spend is forecast to be $113M (EGI) as summarized in **Table 5.2.4-8**. Distribution Stations capital is further summarized as part of EGD's total 10-year capital plan in **Section 6**. See **Appendix B – IRP** for the status of the outcomes of the IRP assessment process, including the binary screen and the status evaluation of IRPAs.

Table 5.2.4-8: Distribution Stations Capital Summary ($ Millions) – EGI[16]

Asset Class Strategy/Investment Name	Program Name	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-Year Forecast
Stations with Auxiliary Equipment Replacement Strategy	Gate, Feeder & A Stations	35.9M	46.1M	36.3M	39.8M	49.8M	61.5M	56.1M	59.9M	58.9M	56.8M	**501.1M**
Lisgar Station		19.2M	2.3M	-	-	-	-	-	-	-	-	**21.5M**
Crowland Station		23.6M	0.6M	-	-	-	-	-	-	-	-	**24.1M**
Compliance Remediation Strategy		2.5M	2.5M	2.6M	2.8M	0.7M	-	-	-	-	-	**11.2M**
Obsolete Heating Equipment Strategy		0.5M	0.6M	3.1M	1.0M	0.5M	-	-	-	0.6M	-	**6.3M**
Odourization System Strategy	Station Rebuilds & B and C Stations	1.7M	2.1M	2.1M	2.5M	2.6M	2.6M	2.6M	2.7M	2.7M	2.6M	**24.1M**
Telemetry Strategy	Gate, Feeder & A Stations	4.0M	8.3M	10.4M	10.7M	9.6M	4.4M	4.5M	4.9M	5.0M	5.0M	**66.7M**
	Station Rebuilds & B	0.1M	0.1M	0.1M	0.1M	0.1M	0.1M	0.1M	0.1M	0.1M	0.1M	**1.2M**

[16] Includes overhead allocation.

Asset Class Strategy/Investment Name	Program Name	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-Year Forecast
	and C Stations											
Facilities Integrity Management Program	Integrity Initiatives	5.8M	5.9M	6.0M	6.0M	6.4M	6.4M	6.3M	6.5M	6.5M	6.3M	**62.2M**
Distribution System Station Replacement Strategy	Station Rebuilds & B and C Stations	42.7M	40.1M	36.1M	38.4M	26.0M	30.7M	34.3M	22.0M	19.8M	26.8M	**316.8M**
Header Station Replacement Program		1.2M	1.2M	1.2M	1.2M	1.3M	1.3M	1.3M	1.3M	1.3M	1.3M	**12.4M**
Customer Station Replacement Program		1.2M	1.3M	1.3M	1.3M	1.4M	1.4M	1.4M	1.4M	1.4M	1.4M	**13.4M**
Inside Regulator Room Program	Inside Regulator & ERR Program	3.8M	3.8M	3.9M	3.9M	4.2M	4.1M	-	-	-	-	**23.8M**
CNG Strategy	CNG	4.7M	2.9M	4.2M	1.0M	1.1M	1.1M	1.1M	1.1M	1.2M	1.1M	**19.5M**
Stations Painting Program	Station Rebuilds & B and C Stations	2.5M	2.8M	2.6M	2.6M	2.8M	2.8M	2.7M	2.8M	2.8M	2.7M	**27.1M**
Total		**149.3 M**	**120.6M**	**109.8M**	**111.4M**	**106.5M**	**116.3M**	**110.4M**	**102.8M**	**100.2M**	**104.2M**	**1131.5M**

5.2.5 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 defence to prevent overpressure to the customer. Unlike customer stations (described in **Section 5.2.4**), these assets support the delivery of gas primarily to customers consuming volumes less than 17.0 m³/h at a typical pressure 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: (1) measurement, (2) pressure regulation and overpressure protection, and (3) belowground and internal piping.

5.2.5.1 Utilization Hierarchy

The asset class hierarchy for the Utilization asset class is summarized in **Figure 5.2-72**.

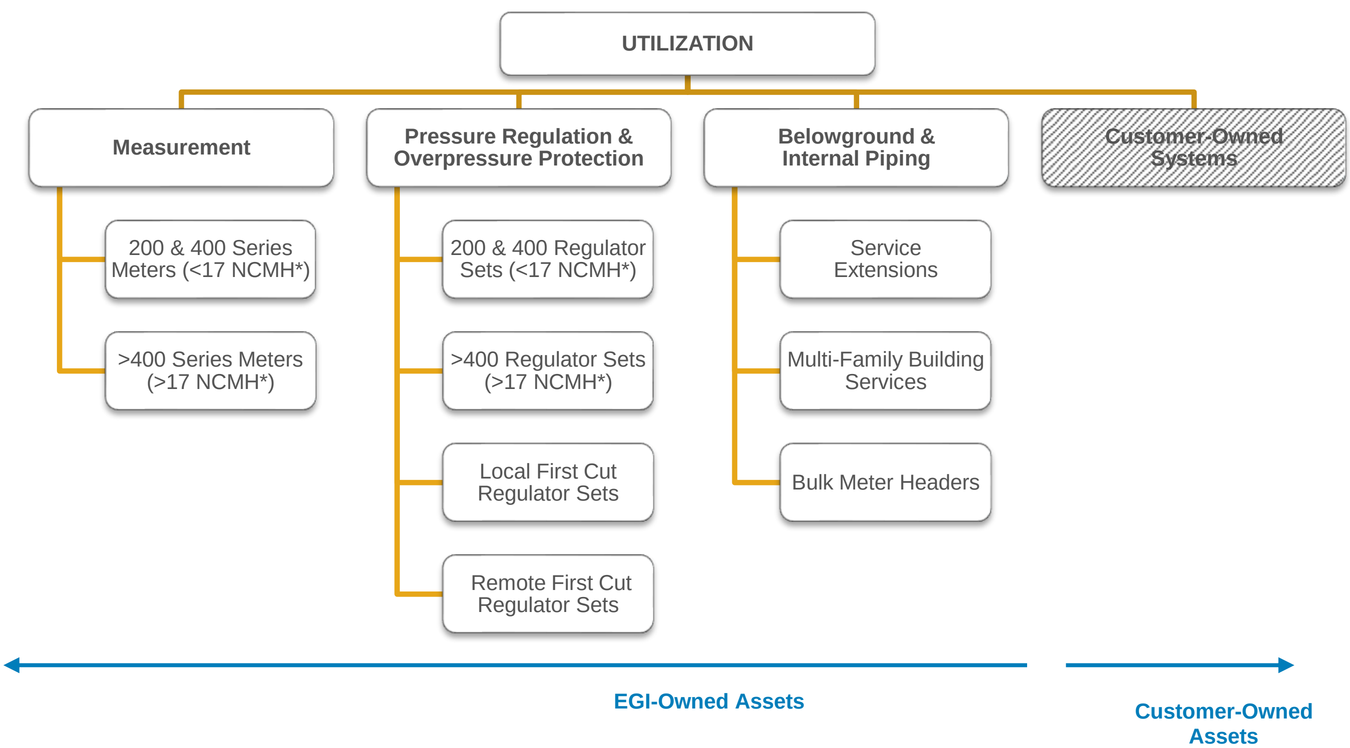


Figure 5.2-72: Utilization Asset Class Hierarchy

Notes:

- Customer-owned systems are included for illustrative purposes only
- *Normal Cubic Metres per Hour

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. To mitigate supply chain challenges, EGI can substitute 200 & 400 class diaphragm meters with ultrasonic meters as required to continue connecting new customers and completing out of date meter exchanges pending industry approvals.

- 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.
- 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.

- **Electronic Volume Correctors** (**EVCs**) typically receive volume measurement inputs from a meter. EVCs measure the temperature and pressure and correct the measured volume for both.

Pressure Regulation and Overpressure Protection Systems regulate the delivery of gas at a pressure appropriate for customer-owned gas-firing appliances and are the last line of defence for overpressure protection.

With the exception of customers connected to low-pressure mains, each customer location has at least one regulator and one overpressure safety device installed to prevent gas entering the building at an unsafe pressure in the event of a malfunction. 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 in the Utilization asset class are regulated to deliver low pressure, typically at 7" wc.
- **Safety devices** prevent downstream overpressure and are the last line of defence to prevent potentially hazardous conditions. Three typical safety devices used in the Utilization asset class are: (1) internal relief valves, (2) external relief valves and (3) overpressure cut-offs.
- **Piping on regulator sets** refers to any of the aboveground piping between the shut-off valve (commonly referred to as a shutoff or lockwing valve) and the meter outlet.

Belowground 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 belowground asset called a Service Extension. Service Extensions are belowground pipe between the regulator outlet and the meter inlet. This belowground piping is necessary in some configurations but is susceptible to corrosion and can require 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 building.

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 5.2-73**).

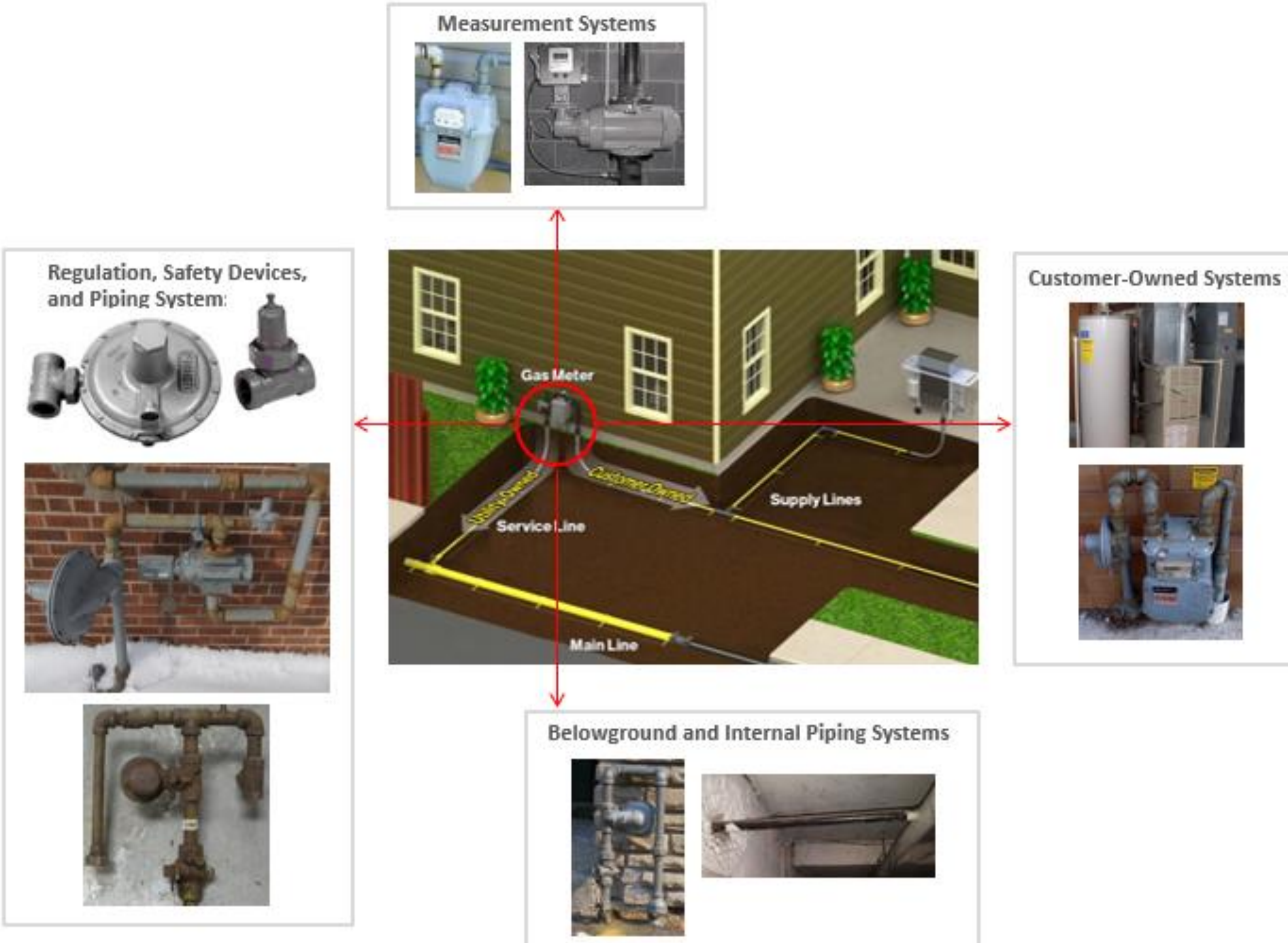


Figure 5.2-73: Utilization Assets Illustration

5.2.5.2 EGI's Customer Classifications

EGI's distribution network delivers natural gas to a range of customers throughout Ontario. **Table 5.2.5-1** describes EGI's customer classifications.

5.2.5.3 Utilization Inventory

Utilization assets include all assets downstream of the shut-off valve and upstream of the meter outlet. The utilization asset subclass delivers natural gas to a range of customers. **Table 5.2.5-1** describes EGI's customer classifications.

Table 5.2.5-1: 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.

Customer Type	Subtype	Customer Definition
Multi-Family / Apartment Uses natural gas for residential purposes in a large building with multiple residential suites that are individually metered.	Apartment New	A traditional apartment customer and is a multi-residential dwelling containing more than six units that are metered individually.
	Apartment 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.

Over 90% of customers are residential, with the remaining being mostly commercial. With 3.8 million EGI customers requiring low pressure delivery, understanding and maintaining the health of these assets is a critical part of providing safe and reliable gas delivery. **Figure 5.2-74** to **Figure 5.2-77** profile EGI's existing customer base by type and location. For a map of the EGI distribution operating regions, see **Figure 2.3-2**.

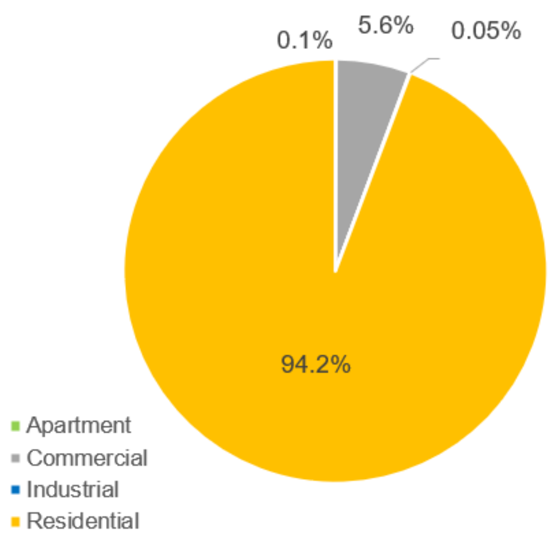


Figure 5.2-74: Customer Breakdown by Type – EGD Rate Zone

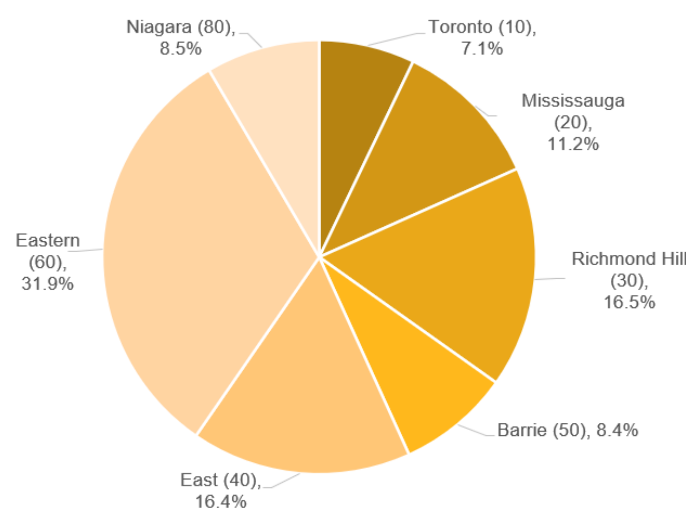


Figure 5.2-75: Customer Breakdown by Area – EGD Rate Zone

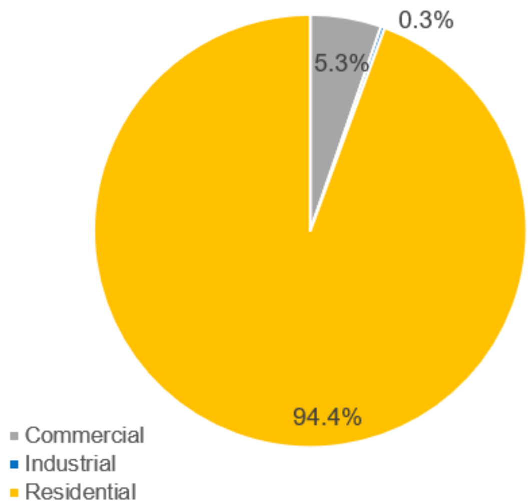


Figure 5.2-76: Customer Breakdown by Type – Union Rate Zones

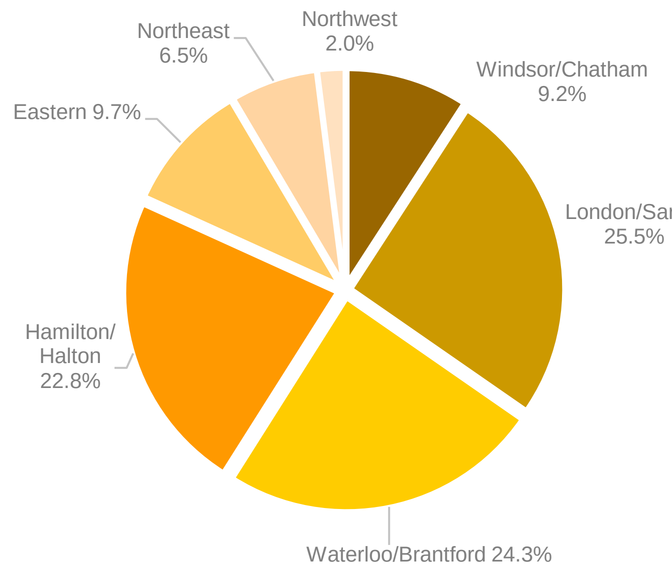


Figure 5.2-77: Customer Breakdown by Area – Union Rate Zones

For the Union rate zones, efforts are underway to recategorize multi-family/apartment customer data to align customer classifications as part of integration activities.

Table 5.2.5-2 lists the inventory details for the Utilization asset class.

Table 5.2.5-2: Utilization Asset Class Inventory[17]

Asset Subclass	EGD Rate Zone	Union Rate Zones
Measurement Systems		
200 & 400 Series Meters (<17 NCMH*)	2,232,345	1,503,843
>400 Series Meters (>17 NCMH*)	68,033	44,024
Pressure Regulation & Overpressure Protection Systems		
200 & 400 Regulator Sets (<17 NCMH*)	2,018,115	1,514,650
>400 Regulator Sets (>17 NCMH*)	90,229	26,279
Local First Cut Regulator Sets	25,093	25,205
Remote First Cut Regulator Sets	10,679	
Belowground and Internal Piping Systems		
Service Extensions	12,457	N/A
Multi-Family Building Services	3,002	N/A
Bulk Meter Headers	39	N/A

**Normal Cubic Metres / Hour*

[17] Inventory as of November 30, 2021.

For the EGD rate zone, the number of meters includes those at Customer Stations within the Distribution Stations Asset Class (see **Section 5.4**). The number of regulators exclude the regulators at customer stations. The populations of >400 Series Regulator Sets, local and remote first cut regulator Sets have stations excluded.

For Union rate zones, the regulators at customer stations are excluded. The double cut regulator sets may include Customer Stations – this will be refined as more asset population information is available. The inventories for belowground and internal piping systems are not currently available. The inventories for Local First Cut Regulator Sets and Remote First Cut Regulator Sets are combined and include a portion of the customer stations, EGI's DIMP is developing a field survey to identify and validate each subpopulation.

5.2.5.4 Utilization Condition and Strategy Overview

Table 5.2.5-3: Utilization Condition and Strategy Overview

Asset Subclass	Avg. Age (Year)	Condition	Risk / Opportunity	Maintenance Strategy	Replacement / Renewal Strategy
Measurement Systems **200 & 400 Series Meters (<17 NCMH)** **>400 Series Meters (>17 NCMH)**	**200 Series Meters:** 24 to 27 years old **400 Series Meters:** 13 to 15 years old **>400 Series Meters:** 16 to 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.	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. **Financial Risk:** 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. 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.	The maintenance strategy for meters is to continue with the current MXGI program and managing non-program exchanges. Reactive maintenance, based on operating standards, is on an as-needed basis to address customer leaks and/or emergency calls.	EGI's replacement/renewal strategy for replacing is through: • **Meter Purchases:** Review 10-year meter replacement forecasts and smooth purchase requirements by adjusting replacement dates within regulations. • **MXGI Program**: Follow the Measurement Canada regulated exchange program (MXGI) which replaces meters before their measurement seal expires. This approach optimizes sampling and meter group replacement costs, to stabilize workload and meter purchases as some years have larger populations to survey.
Regulation, Safety and Piping Systems: **200 & 400 Regulator Sets (<17 NCMH)**	Dependent on meter and regulator type: between 20 to 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 & 400 Series Meters is unlikely to occur before 30 years of age.	Majority of customers are connected to the distribution system through 200 & 400 Series Regulator Sets. Not maintaining these assets can lead to: **Public Health and Safety Risk**: Loss of containment, threat of overpressuring customer piping, possibly leading to explosion **Financial Risk**: Repair, commodity loss, relights, potential property damage costs **Operational:** Customer service disruptions **Environmental:** GHG emissions and environmental impact of a leak	The maintenance strategy for 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 replacement/renewal strategy for replacing is through: • **MXGI Program:** Exchanging regulators during MXGI inspections prevents the population from reaching the wear-out phase. • **Opportunistic Replacement:** If found to be 20 years or older, Regulator Sets are opportunistically replaced. • **Targeted Inspection and Remediation Program:** The Targeted Inspection and Remediation Strategy is used to remediate high-priority condition issues identified through EGI's DIMP. Through the DIMP, surveys collect information on the failure rates of assets, informing future policy decisions on replacement frequency.
Regulation, Safety and Piping Systems: **>400 Regulator Sets (>17 NCMH)**	Dependent on meter and regulator type: between 20 to 30 years old	Condition findings include corrosion of piping and regulators and not complying with installation specifications. The inspection program is planned to target the entire population of the >400 Series Regulator Sets.	The risks identified for >400 Series Regulator Sets are the same as 200 & 400 Series Regulator Sets. Since delivery rates for >400 Series Regulator Sets are higher than delivery rates for the 200 & 400 Series, the consequences are potentially greater and put a higher number of end users at risk.		
Regulation, Safety and Piping Systems: Local First Cut Regulator Sets	Dependent on meter and regulator type: between 20 to 30 years old	Failure history and trending indicate the wear-out phase for regulators associated with 200 & 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.	The risks identified for Local First Cut Regulator Sets are the same as 200 & 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.		
Regulation, Safety and Piping Systems: Remote First Cut Regulator Sets	Dependent on meter and regulator type: between 20 to 30 years old	Remote first cut regulator set sites older than 15 years were determined to have more significant condition issues. Remote 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.	The risks identified for Remote First Cut Regulators are the same as Local First Cut Regulator Sets**.** As Remote First Cut 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.		

Asset Subclass	Avg. Age (Year)	Condition	Risk / Opportunity	Maintenance Strategy	Replacement / Renewal Strategy
Underground/ Belowground/ Internal Piping Systems	N/A	**Service Extensions:** A sample survey of Service Extensions showed that some subsets have a population that requires cathodic protection. **Multi-Family Building Services:** Generally, corrosion is found where the pipe intersects with the concrete wall; any severe corrosion that could affect safety is remediated. **Bulk Meter Headers:** Common issues include: • No clear demarcation points between EGI and customer assets • Obsolete regulators 20 years and older • Nonadherence to current installation and maintenance specifications • Vent clearances and configurations not met, not all fittings located above ground and obsolete components	The risks identified include Financial, Environmental, Operational and Public Health and Safety Risk. **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 buildings serviced are higher-occupancy units, there is potential for a higher consequence of failure. EGI is obtaining further information on these assets to better understand and manage asset risk.	The maintenance strategy is to continue to conduct the Targeted Inspection and Remediation Program based on operating standards through the Distribution Integrity Management Program (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 is through: • **Opportunistic Replacement**: Replace Service Extensions when the gas service is replaced and during planned city sidewalk/road replacements. • **Targeted Inspection and Remediation Program:** Sampling will be used to assess risks and validate the condition of the assets through the Leak Survey and Cathodic Protection surveys. Continue to review the feasibility of an aboveground inspection tool. Remediate high-priority condition issues identified through the Leak Survey and Cathodic Protection programs.
Customer-Owned Systems	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.	Failure of these components can cause loss of containment and appliance malfunction, resulting in public health and safety risk.	EGI inspects customer-owned assets at the time of initial installation and after conducting relights. 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.

5.2.5.5 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 & 400 Series Meters (<17 NCMH) have a capacity 17.0 m^3/h or less and >400 Series Meters (>17 NCMH) have a capacity 17.0 m^3/h or greater.

Certain meters have instruments (electronic volume correctors) that perform compensation to accurately measure gas flow.

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.

The majority of EGI's customer base are residential and small commercial customers whose meter has been a 200 or 400 series diaphragm meter for many decades. Technological advances have introduced ultrasonic meters which are becoming available for the 200 & 400 series meters. EGI has an interest in upgrading its meters to ultrasonics as they offer enhanced safety features and can provide more insight back to the utility in real time when connected to a network. Diaphragm meters are becoming more difficult to procure as one of the major diaphragm meter manufacturers discontinued production of their line in 2021, in addition to other supply chain issues, therefore EGI is substituting small diaphragm meters with ultrasonic meters to continue to connect new customers and execute meter exchanges. EGI is also exploring an Advanced Metering Infrastructure (AMI) deployment to complement the introduction of ultrasonic meters to our system. Potential costs associated with AMI deployment have not been included in the capital expenditures of this AMP.

5.2.5.5.1 CONDITION METHODOLOGY

The replacement of the meter population is prescribed by Measurement Canada requirements and fulfilled by EGI's meter exchange program. 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 & 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 life span (10 years for most 200 series meters, 7 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 life span) is given to the meter group. If the sample meters fail, the meters are removed from service. Meter groups that pass require further testing after their next extended life span expires (8, 6, 4, or 2 years).

>400 Series Meters (>17 NCMH): Rotary meters, ultrasonic, turbine meters and instruments do not qualify for sample inspection. The life-cycle management for these meters is to renew and replace prior to seal expiry. Rotary meters expire after 16 to 20 years, ultrasonic meters at 10 years, turbine meters at 6 years and instruments at 7 to 12 years.

Exchanged meters are processed at the meter shops on EGI premises, as EGI has a facility that has Measurement Canada accreditation. Processing includes labelling, cleaning and performance testing. Meters are also sent off site to accredited meter inspections facilities as required. Meters are also exchanged when malfunctioning, when customer load changes, or if involved in billing investigations.

5.2.5.5.2 CONDITION FINDINGS

The MXGI Program is designed to keep the in-service meter population healthy. The length of meter life extensions is dependent on sample group performance. In addition, the maximum achievable extension decreases as sampling of a group increases. For 200 & 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 5.2.5-4**.

Table 5.2.5-4: 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
2020	36,263	19,735	31,323	13,559

Non-program meter exchanges are attributed to the reasons listed in **Figure 5.2-78** and **Figure 5.2-79**. 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.

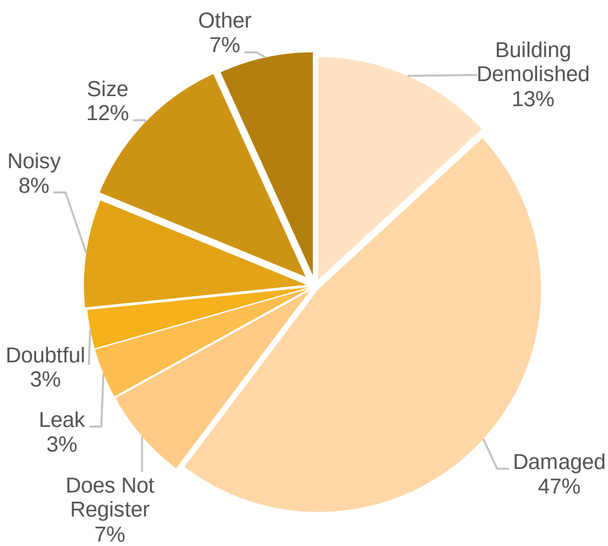


Figure 5.2-78: Typical Causes of Non-Program Meter Exchanges) – EGD Rate Zone

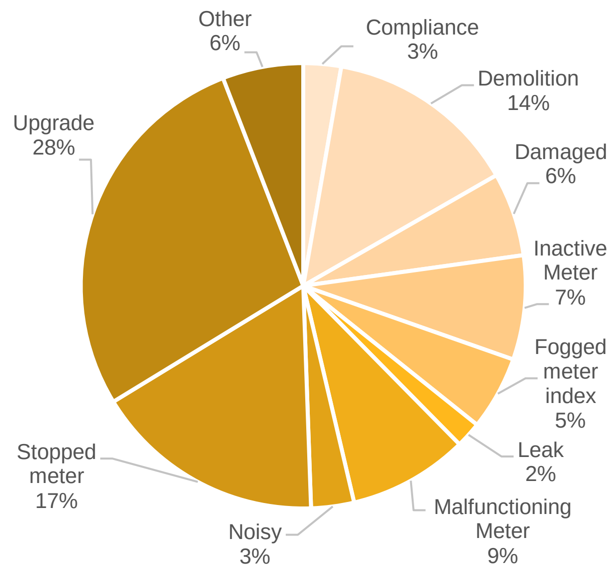


Figure 5.2-79: Typical Causes of Non-Program Meter Exchanges) – Union Rate Zones

5.2.5.5.3 RISK AND OPPORTUNITY

5.2.5.5.3.1 MXGI Risk

For detail on the risk and opportunity, see **Table 5.2.5-3**.

5.2.5.5.3.2 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 the majority are located outside customer premises. Very few meters are returned due to leaks. 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.

5.2.5.6 Pressure Regulation and Overpressure Protection Systems

EGI is accountable for managing over 3 million regulator sets that deliver low pressure natural gas to customers. These critical assets act as the last line of defence against overpressure. A regulator set is comprised of a regulator that reduces distribution gas pressure to delivery pressure, piping and overpressure protection devices. Proper performance of these assets is vital for the health and safety of customers, the public and employees. **Table 5.2.5-5** describes the four subsets of this asset subclass:

Table 5.2.5-5: Regulator Set Descriptions

Regulator Set	Description
200 & 400 Series Regulator Sets (< 17 NCMH)	These regulator sets provide low pressure delivery (typically 7" wc) to primarily residential customers. They are associated with meters having capacities of 17.0 m^3/h or less.
>400 Series Regulator Sets (>17 NCMH)	These regulator sets provide low pressure delivery (typically 7" to 10" wc) to high-volume customers. They are 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 in close proximity at the same assembly. The first cut regulator reduces pressure from a higher pressure (>100 psig) to an intermediate pressure (typically 60 psig) and the service cut regulator reduces pressure from intermediate to low pressure (up to 7" wc).
Remote First Cut Regulator Sets	These regulator sets are the same as the Local First Cut Regulators, but the first cut is typically located close to the property line and the service continue below grade to the service cut regulator adjacent to the premises. **Note:** Remote First Cut Regulator Sets are also known as farm taps or Property Line Post Regulator Sets (PLPRs).

5.2.5.6.1 200 & 400 SERIES REGULATOR SETS (< 17 NCMH)

The 200 & 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 MXGI Program. Based on the MXGI Program requirements, replacements can happen as soon as after 10 years of service. EGI collects 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.

For the age distribution of the 200 & 400 Series Regulator Sets for each rate zone, see **Figure 5.2-80** and **Figure 5.2-81**.

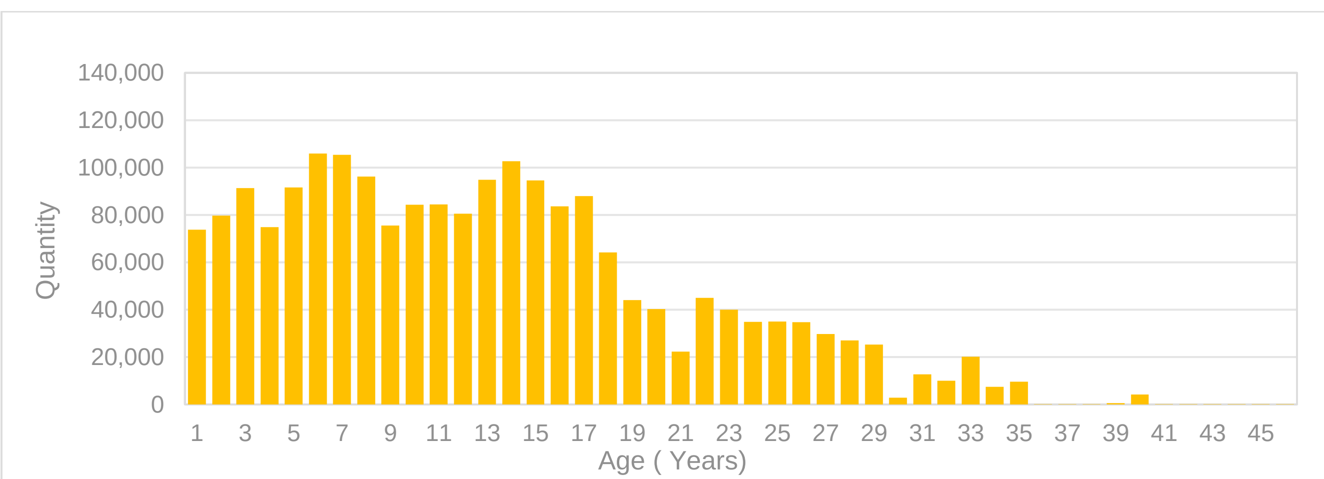


Figure 5.2-80: Age Distribution of 200 & 400 Series Regulator Sets – EGD Rate Zone

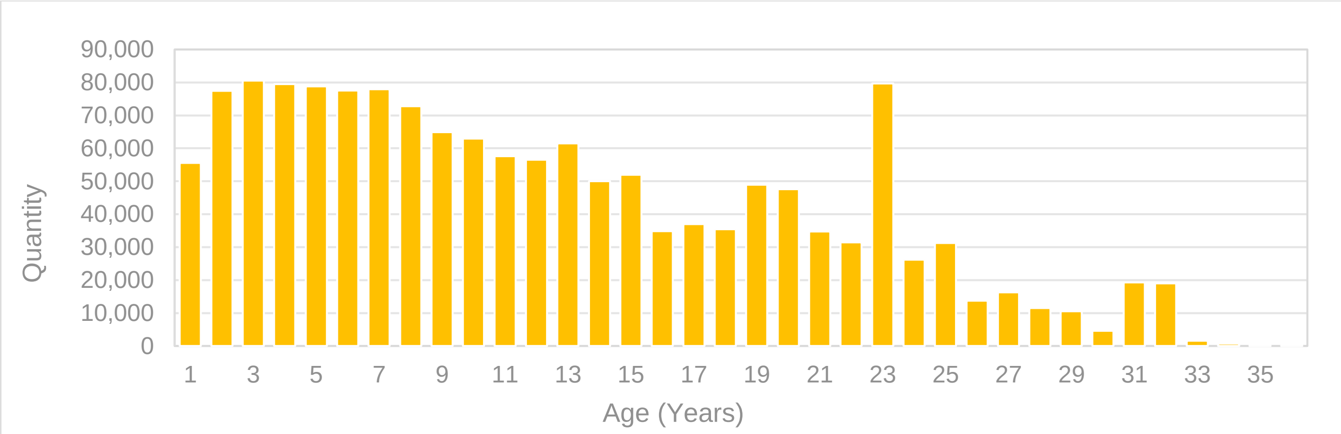


Figure 5.2-81: Age Distribution of 200 & 400 Series Regulator Sets – Union Rate Zones

5.2.5.6.1.1 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 overpressure) 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 5.2.5-6.**

Table 5.2.5-6: 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.
	Regulator touching customer supply lines	Regulators touching customer supply lines can cause electrical continuity of belowground and aboveground systems. This can promote migration of corrosion between belowground and aboveground piping.
	Regulator too close to ground	Regulators that touch the ground are more susceptible to corrosion.
External reliefs	External relief missing on downstream regulator	Absence or failure of this component removes overpressure 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.

Component	Issue	Outcome
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.
Fittings **Regulator, Piping, Fitting, External reliefs**	Buried fittings	Fittings, typically shut-off valves, must be above ground to shut off gas in emergencies and avoid corrosion.
	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.

These issues can contribute to failure of the regulation system and can cause overpressured 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.

5.2.5.6.1.2 Condition Findings

Failure history and trending indicates that the wear-out phase for regulators associated with 200 & 400 series meters is unlikely to occur before 30 years of age. The current failure rate is very low relative to the total population. EGI replaces regulators proactively at the time of the meter exchange and before they fail.

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.

Three condition categories evaluated for 200 & 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., overpressure 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, overpressure or gas escapes. Non-failure replacements may be due to handling issues, customer load changes, changes to building openings, obsolete regulators, corrosion and damages. The quantity of regulator exchanges independent of meter exchanges is relatively low. Analysis will continue to distinguish failure and non-failure exchanges within this group of assets.

Corrosion of piping and regulators: A survey to investigate corrosion on regulator sets was carried out across the EGD rate zone in 2016. Corrosion distribution by age is shown in **Figure 5.2-82**.

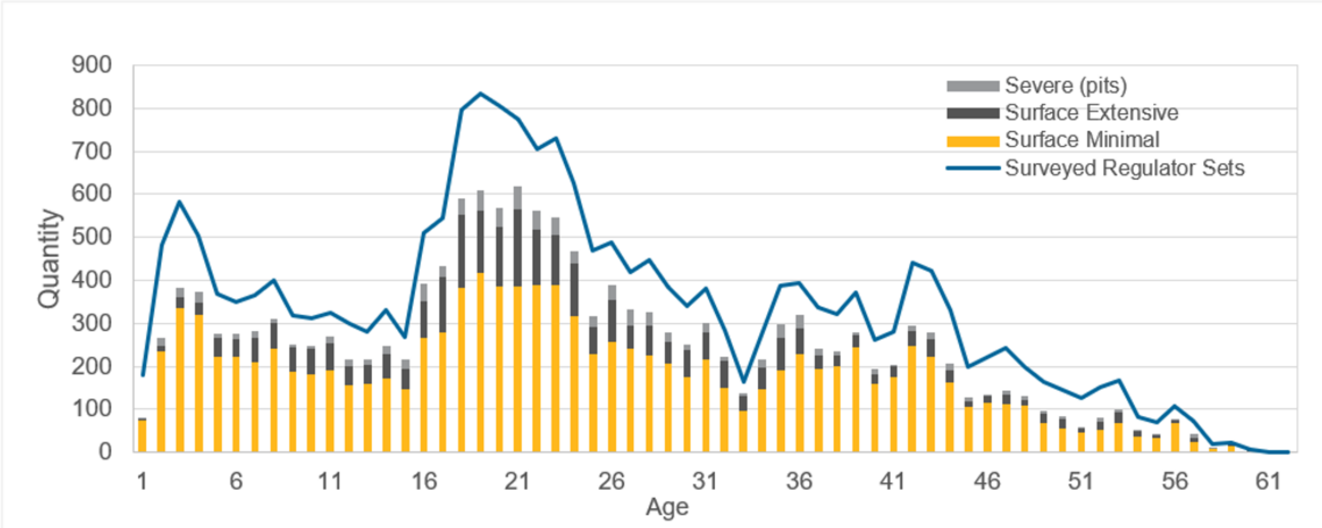


Figure 5.2-82: 200 & 400 Series Regulator Sets - Corrosion Distribution by Age – EGD Rate Zone

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 5.2-82** shows that the majority of regulator sets have minimal surface corrosion and only 5% were categorized as severe. As part of integration activities, an initiative to obtain similar data for the Union rate zones is underway.

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.

5.2.5.6.1.3 Risk and Opportunity

Any 200 & 400 Series Regulator Sets in poor condition expose EGI to Financial, Public Health and Safety, Operational and Environmental Risk.

The safety risk associated with regulator sets is associated with the loss of gas containment within the building (including gas migration). Regulators (and associated relief valves) control gas pressure to protect the customer's piping and premises from overpressure. An overpressure event can result in damage to downstream equipment, loss of containment within the building, gas accumulation and a potential incident. The probability of a public health and safety risk is low due to the MXGI Program governing these assets.

Failure of these assets is most commonly linked to financial risk. Overpressure and loss of containment generates costs associated with emergency response calls, repairs, commodity loss, relighting customers' gas appliances, property damage and/or other claims. The operational risk includes customer service disruptions and media coverage resulting from these events may result in reduced customer confidence in EGI.

Environmental risks include GHG emissions and environmental impact of a leak. EGI continues to take steps to gather necessary information and better manage these assets and their risks.

5.2.5.6.2 >400 SERIES REGULATOR SETS (> 17 NCMH)

The >400 Series Regulator Sets are primarily used by commercial, industrial and high-density residential customers. Failure of these regulator sets has the potential to cause overpressure to a customer's supply line and appliances. Overpressure can result in a loss of containment within the building, potentially allowing gas migration. The current policy states commercial regulators are opportunistically exchanged if found to be 20 years or older. A risk assessment of this asset class is planned which will assist in the development of an integrated program.

Figure 5.2-83 and **Figure 5.2-84** show the age distribution of >400 Series Regulator Sets in EGD and Union rate zones respectively. Historically, >400 Series Regulator Sets have not been tracked as separate asset components in the EGD or Union systems of record, therefore, the installation date of the service they are associated with has been used as a proxy to determine the age.

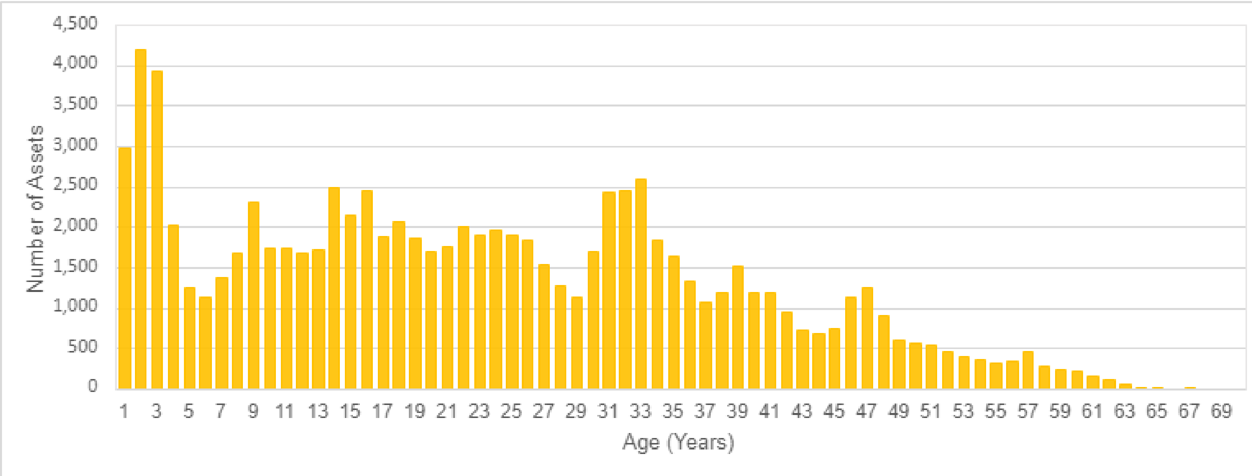


Figure 5.2-83: Age Distribution of >400 Series Regulator Sets – EGD Rate Zone

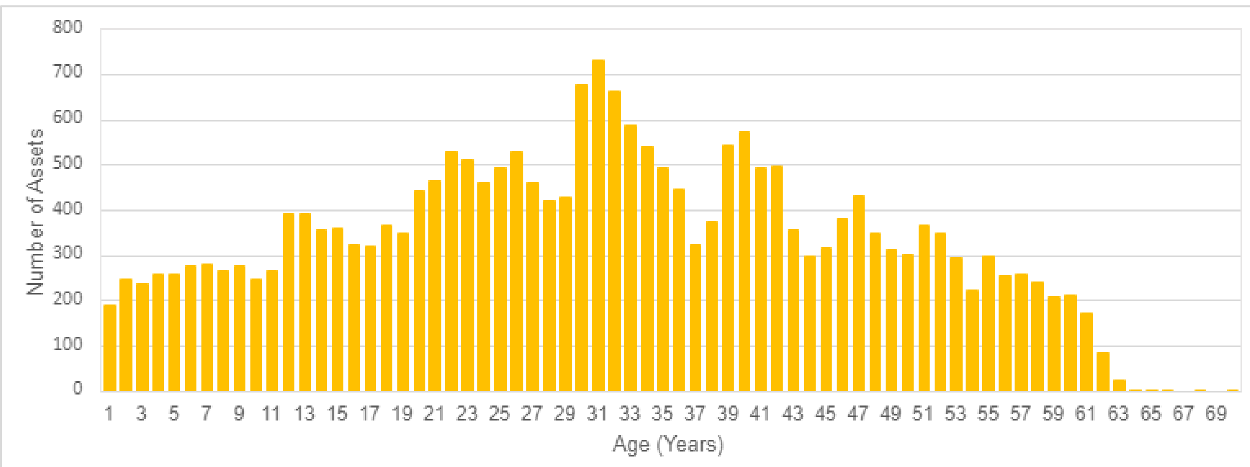


Figure 5.2-84: Age Distribution of >400 Series Regulator Sets – Union Rate Zones

Commercial Meter Manifolds are a subset of >400 Series Regulator Sets. These installations of multiple banked meters are typically located in commercial plazas. As EGI has not historically provided specifications on the addition of new meters to existing manifolds or criteria required for regulator set rebuilds, this configuration is more prone to condition issues and nonadherence to installation specifications. The population does not include all meter manifolds as this information is not available in any system of record.

5.2.5.6.2.1 Condition Methodology

The condition methodology for >400 Series Regulator Sets is the same as for the 200 & 400 Series Regulator Sets (see **Section 5.2.5.6.1.1**).

5.2.5.6.2.2 Condition Findings

In 2021, an inspection survey was performed on a statistically significant random sample (95% confidence level, 5% margin of error) of EGI's >400 Series Regulator Sets. As part of this survey, two main condition categories were evaluated for these regulator sets: corrosion of piping and regulators and adherence to installation specifications.

An integrity inspection work plan targeting the entire EGI population of the >400 Series Regulator Sets is currently being developed for this asset subclass including visual assessment of condition and degradation rating of components to be used as an early indicator of failure resulting in a proactive remediation approach. Future replacement work will be used as an opportunity to evaluate the performance of pressure-controlling devices.

Corrosion of piping and regulators*:* The survey included a visual assessment of the condition including corrosion rating of service regulators, external relief valves, valving, and service piping for this asset subclass as well as risers (see **Figure 5.2-85**). Minimal and moderate external corrosion does not affect the engineering design and safe operation of the >400 regulator assets and does not present any immediate safety concerns. Sites with severe pitting corrosion are identified for remediation.

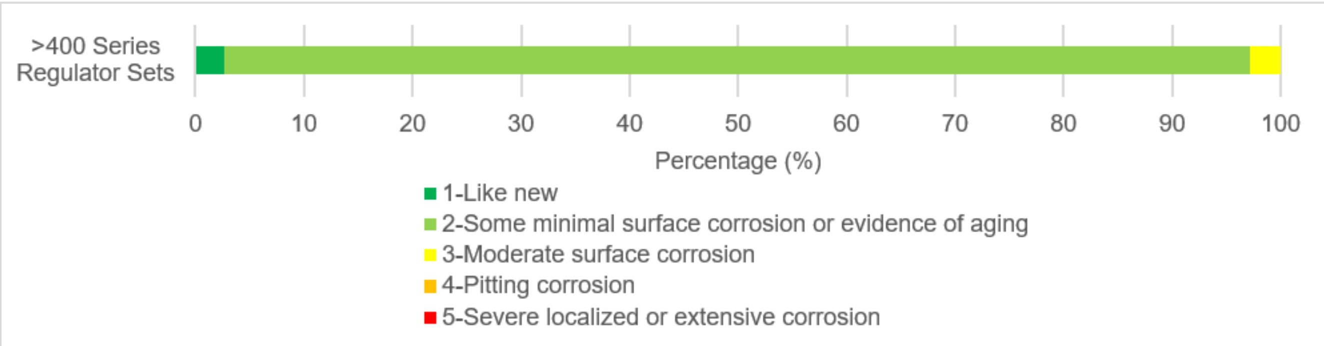


Figure 5.2-85: **>400 Series Regulator Sets Corrosion Assessment – EGI**

Adherence to installation specifications*:* The sample survey indicated that a small percentage of >400 Series Regulator Sets had issues related to adherence to current installation specifications. The most frequent issues identified were:

- Improper vent orientation
- Vent clearance issues
- Damage to the regulator cap
- Missing vent screen
- Presence of vent shields
- Regulator touching pipe
- Regulator within ½ inch of pipe
- Buried fitting
- Inadequate protection

Remediation plans have been created to address and mitigate all sites with identified issues. As the inspection program is expanded to target the entire population of the >400 Series Regulator Sets, additional locations requiring mitigation work will be identified and remediated in the future.

5.2.5.6.2.3 Risk and Opportunity

The risks associated with >400 Series Regulator Sets are the same as the 200 & 400 Series Regulator sets (see **Section 5.2.5.6.1.3**).

Historically, the probability of a >400 series regulator failure is low. These assets 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, therefore, 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 & 400 Series Regulators) services. This results in potentially more severe consequences for safety and financial risks when compared to smaller flow regulator sets.

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, and Quality Assurance (QA) testing on commercial regulators at EGI's Materials Evaluation Centre (MEC) where >400 Regulators are tested at the time of the meter exchange. Risk is further managed through proactive replacement of regulators if, during service calls, they are found to be older than 20 years.

5.2.5.6.3 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), as described in **Table 5.2.5-5**. This configuration is not common and represents an estimated 2% of the total EGI services. The regulator set may also include additional components, such as external relief valves.

Figure 5.2-86 and **Figure 5.2-87** shows the age distribution of local double cut regulator sets in EGD and Union rate zones respectively. For the Union rate zones, the distribution includes both local and Remote First Cut Regulator Sets as there is no asset attribute available in the current system of record to distinguish between the two subpopulations. An integrity inspection program targeting the inspection of the entire double cut regulator set population in the Union rate zones is under development which will allow for identification and validation of each subpopulation.

Historically, Local First Cut Regulator Sets have not been tracked as separate asset components in the EGD or Union systems of record. Therefore, the installation date of the service they are associated with has been used as a proxy to determine the age.

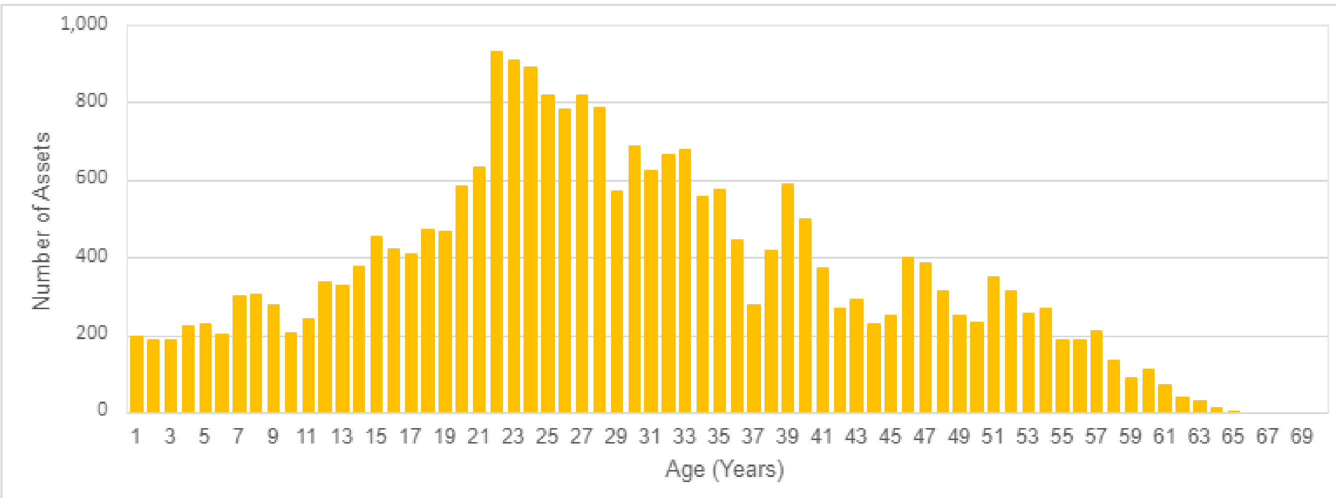


Figure 5.2-86: Age Distribution of Local First Cut Regulator Sets – EGD Rate Zone

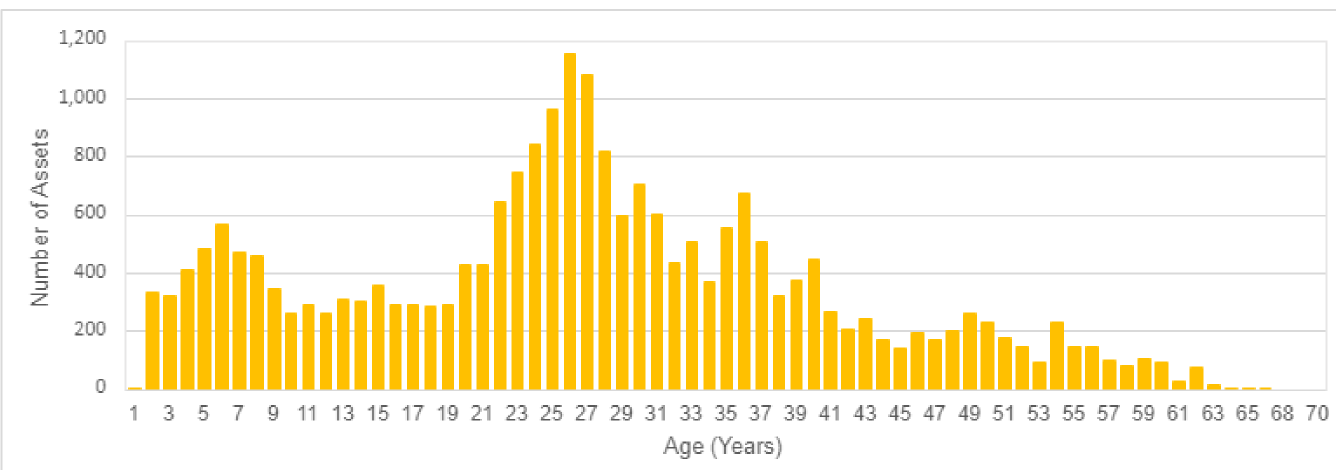


Figure 5.2-87: Age Distribution of Local and Remote First Cut Regulator Sets – Union Rate Zones

5.2.5.6.3.1 Condition Methodology

The condition methodology for Local First Cut Regulator Sets is the same as for the 200 & 400 Series Regulator Sets (see **Section 5.2.5.6.1.1**).

5.2.5.6.3.2 Condition Findings

For more detail on the 2021 inspection survey, see **Section 5.2.5.6.2.2**. The results of the inspection survey for EGI's Local First Cut Regulator Sets are shown in **Figure 5.2-88**.

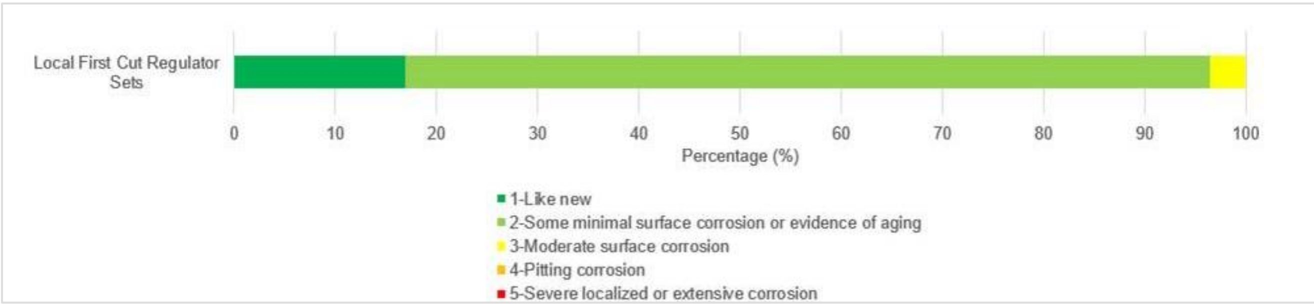


Figure 5.2-88: Corrosion Assessment of Local First Cut Regulator Sets – EGI

Adherence to Installation Specifications: The issues identified from the sample survey are the same as those described in the>400 Series Regulator Sets in the 2021 inspection survey (see **Section 5.2.5.6.2.2**). Remediation plans have been created to address and mitigate all sites with identified issues. As the inspection program is expanded to target the entire population of Local First Cut Regulator Sets, additional locations requiring mitigation work will be identified and remediated in the future.

5.2.5.6.3.3 Risk and Opportunity

The risks associated with Local First Cut Regulator Sets are the same as the 200 & 400 Series Regulator Sets (see **Section 5.2.5.6.1.3**). Local First Cut Regulator Sets present 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 overpressure protection devices installed in series.

5.2.5.6.4 REMOTE FIRST CUT REGULATOR SETS

Table 5.2.5-5 describes Remote First Cut Regulator Sets, the majority of these double cut regulator sets are found in rural areas. **Figure 5.2-89** shows the age distribution of Remote First Cut Regulator Sets for the EGD rate zone. For the Union rate zones' Local and Remote First Cut Regulator age distribution, see **Figure 5.2-87**. An Integrity inspection work plan targeting the entire population of the Remote First Cut Regulator Sets in the rate zones has been developed to include visual assessment of condition and degradation rating of components. This will be used as an early indicator of failure resulting in a proactive remediation approach.

Historically, Remote First Cut Regulator Sets have not been tracked as separate asset components in the EGD or Union systems of record; therefore, the installation date of the service they are associated with has been used as a proxy to determine the age.

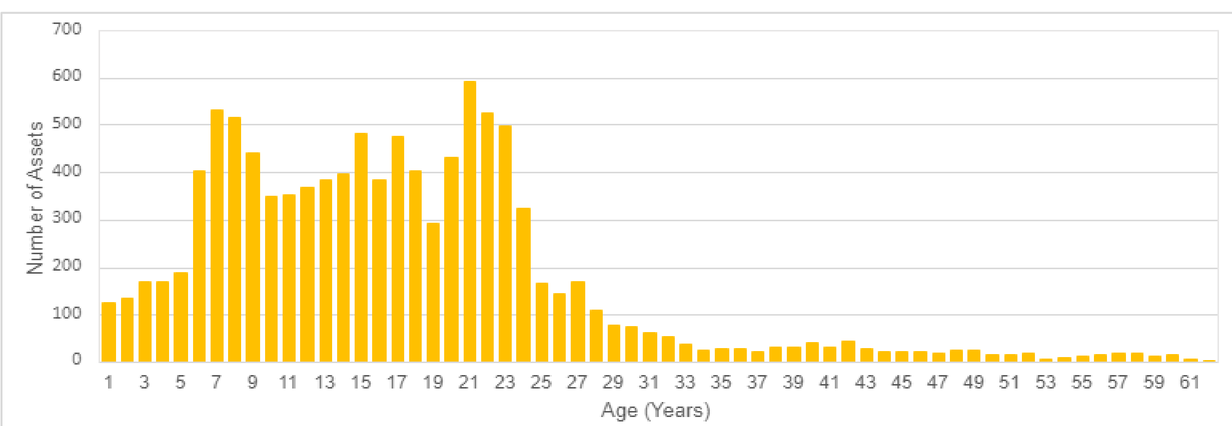


Figure 5.2-89: Age Distribution of Remote First Cut Regulator Sets – EGD Rate Zone

5.2.5.6.4.1 Condition Methodology

For the condition methodology, see **Section 5.2.5.6.1.1**. In addition, a component-based Failure Mode and Effect Analysis (FMEA) was performed through subject matter advisor (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.

Based on the FMEA, the main critical components for Remote First Cut Regulators Sets are regulators, inlet and outlet shutoff 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 identified the lack of maintenance as one of the main causes of failures on these critical components.

5.2.5.6.4.2 Condition Findings

For more detail on the 2021 inspection survey, see **Section 5.2.5.6.2.2**. The results of the inspection survey for Remote First Cut sets are shown in **Figure 5.2-90.**

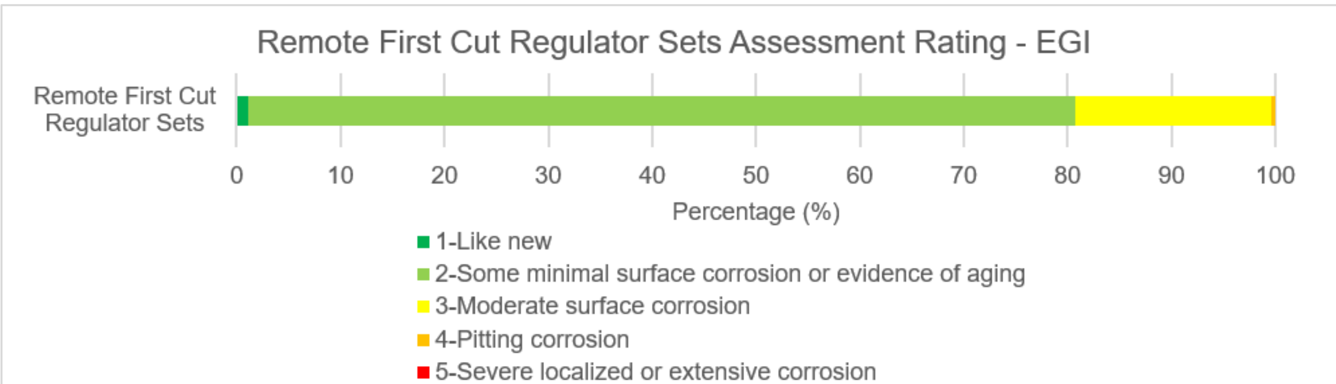


Figure 5.2-90: Remote First Cut Regulator Sets Assessment Rating – EGI

Adherence to Installation Specifications: The sample survey indicated that remote first cut regulator had issues related to adherence to installation specifications. The most frequent issues identified for Remote First Cut Regulator Sets were:

- Improper vent orientation
- Vent clearance issues
- Damage to the regulator cap
- Missing vent screen
- Obsolete regulators
- Buried fitting
- Inadequate protection

Most vintages had some level of nonadherence 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.

Remediation plans have been created to address and mitigate all sites with identified issues in both EGD and Union rate zones. As the Inspection Program is expanded to target the entire population of Remote First Cut Regulator Sets, additional locations requiring mitigation work will be identified and remediated in the future.

5.2.5.6.4.3 Risk and Opportunity

The risks associated with Remote First Cut Regulator Sets are the same as the 200 & 400 Series Regulator Sets (see **Section 5.2.5.6.1.3**). Remote First Cut Regulator Sets present a higher consequence than traditional single cut regulator sets due to the higher pressures managed by two pressure cuts. The failure rate of Remote First Cut Regulator Sets is very low due to the presence of multiple pressure regulators and multiple overpressure protection devices installed in series.

As most Remote First Cut 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.

5.2.5.7 Belowground and Internal Piping Systems

Belowground and Internal Piping Systems refer to piping running below grade and/or piping running inside a building, typically located upstream of inside meters. The Belowground & Internal Piping Systems subclass is categorized into:

Service Extensions: Refer to service piping installed between the regulator (outside of the building) and the meter (inside the building) where the pipe enters the building belowground.

Multi-Family Building Services: Refer 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 instead of each individual level of the building.

Bulk Meter Headers: Refer to gas distribution networks consisting of underground piping downstream of a meter feeding multiple individual customer buildings; regulation occurs downstream of the meter.

5.2.5.7.1 SERVICE EXTENSIONS

Service Extensions, as described in **Section 5.2.5.7**, enter building walls 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. EGD currently has 12,457 Service Extensions. A study is planned in 2022 to determine the number of Service Extensions for the Union rate zones.

Figure 5.2-91 shows the age distribution for Service Extensions. The majority of the population is younger than 25 years, some of the contributing factors 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.

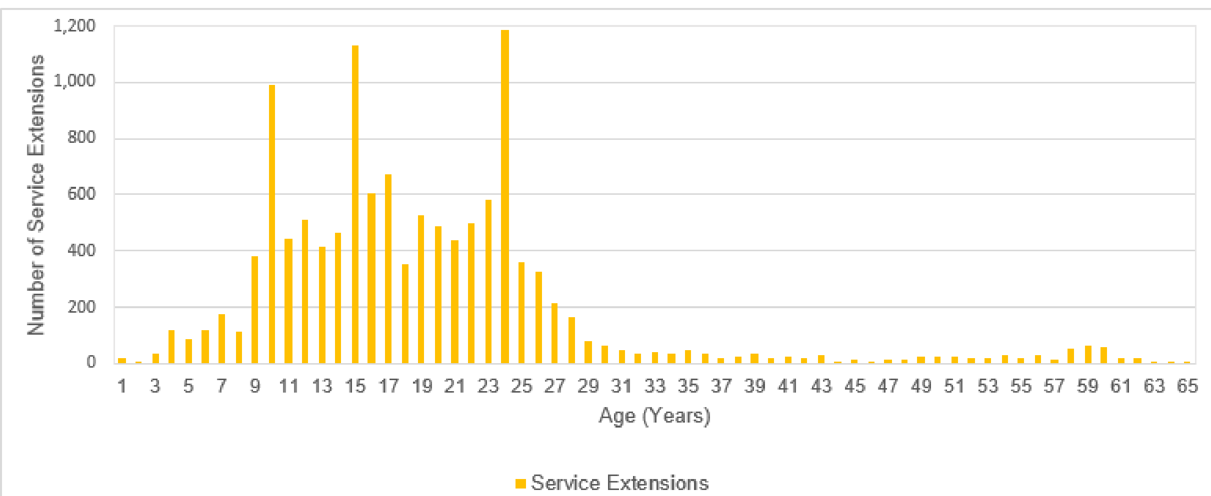


Figure 5.2-91: EGD Demographics – Service Extensions

5.2.5.7.1.1 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. In 2021, a sample of Service Extensions over 25 years of age in the Toronto area were inspected through the DIMP. The inspection consisted of testing the cathodic protection as well as assessing the corrosion and coating condition of the Service Extensions. The inspection is planned to be expanded for the remaining population in EGD and Union rate zones.

The effectiveness of cathodic protection on Service Extensions in the EGI rate zone is estimated by conducting pipe-to-soil inspections on a statistically representative sample; over time, all known services will be inspected. In addition, samples of unprotected Service Extensions are removed to determine wall loss. The sample sites are also inspected prior to removal with nondestructive guided wave testing, designed to detect the magnitude and location of wall loss on buried pipe. Removed samples are inspected for condition and to validate the effectiveness of this technology. Installations are upgraded at all sample sites. The initial sample of Union Service Extensions is expected to occur in 2022. Through integration efforts, the size and condition of the Service Extension population in each rate zone will be established by inspecting all known locations over five years.

5.2.5.7.1.2 Condition Findings

Cathodic protection surveys determine some correlation between age and cathodic protection status (see **Figure 5.2-92**). Newer installations are more likely to be cathodically protected while older Service Extensions are more likely to fail than newer Service Extensions. The results of the sample surveys are used to refine a mechanical model that will determine the degradation rate of unprotected Service Extensions. Sampling validates the functionality of non-destructive guided wave technology for use in future inspections. This population is to be monitored and at this time no proactive program is planned.

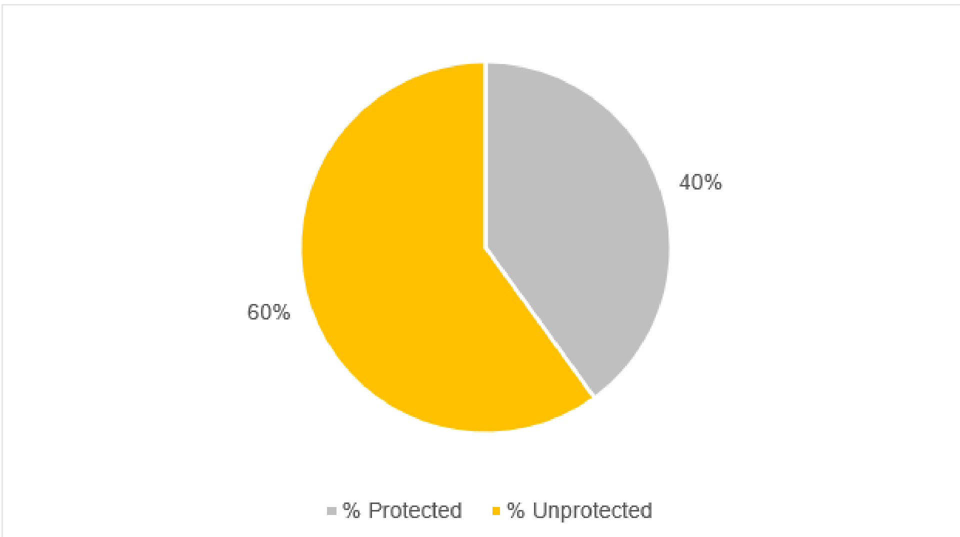


Figure 5.2-92 Percentage of Cathodic Protected/Unprotected Service Extensions

Results of the sample inspection show that the majority of the Service Extensions do not have an active cathodic protection. Approximately 10% of Service Extensions identified with inactive cathodic protection were found to have evidence of corrosion at grade level. The other 90% are operating within the operably tolerable range. The corrosion condition of all the sample survey is classified in **Figure 5.2-93**.

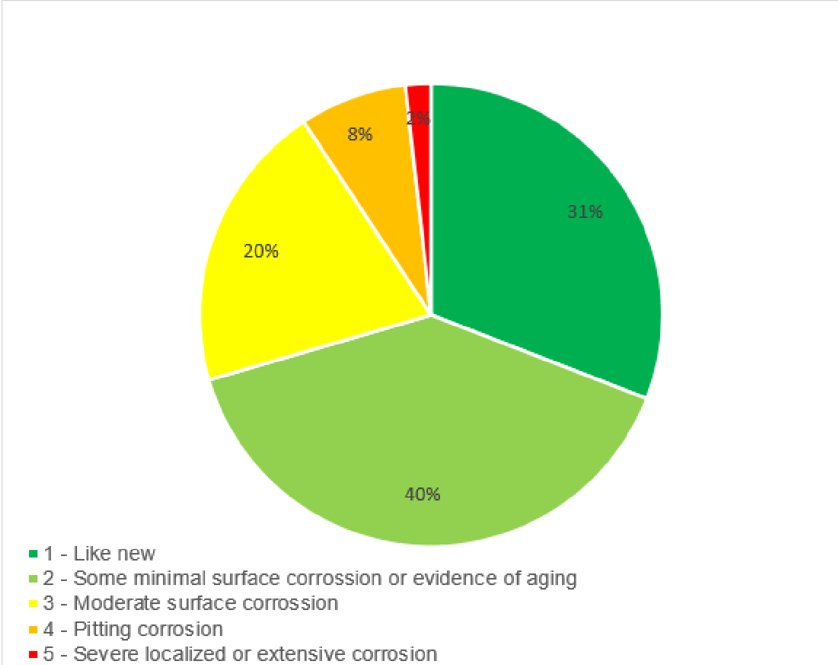


Figure 5.2-93: Corrosion Condition of Unprotected Service Extensions

5.2.5.7.1.3 Risk and Opportunity

If Service Extensions are not cathodically protected and properly coated, they can corrode at a higher rate, 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. Previous sample surveys show 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. 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. The operational risk includes customer service disruptions and media coverage resulting from these events may result in reduced customer confidence in EGI. Environmental risks include GHG emissions and environmental impact of a leak. EGI continues to take steps to gather necessary information and better manage these assets and their risks.

5.2.5.7.2 MULTI-FAMILY BUILDING SERVICES

Multi-family Building Services 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.

5.2.5.7.2.1 Condition Methodology

Multi-family building installations have several additional challenges:

- Piping location creates challenges for leak and cathodic protection surveys.
- Some units may have isolated steel pipe upstream of the meter. EGI is working to ensure that all buildings that have this piping configuration are identified in appropriate systems and placed on a regular maintenance program. As

these locations are added to the survey, there is the possibility that their internal piping will be found to be in poor condition – given that they may not have been previously surveyed.

Figure 5.2-94 shows the distribution of vintages for this asset subclass in the EGD rate zone, as well as the quantity of inside meters per building at these locations. 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 the Targeted Inspection and Remediation Program.

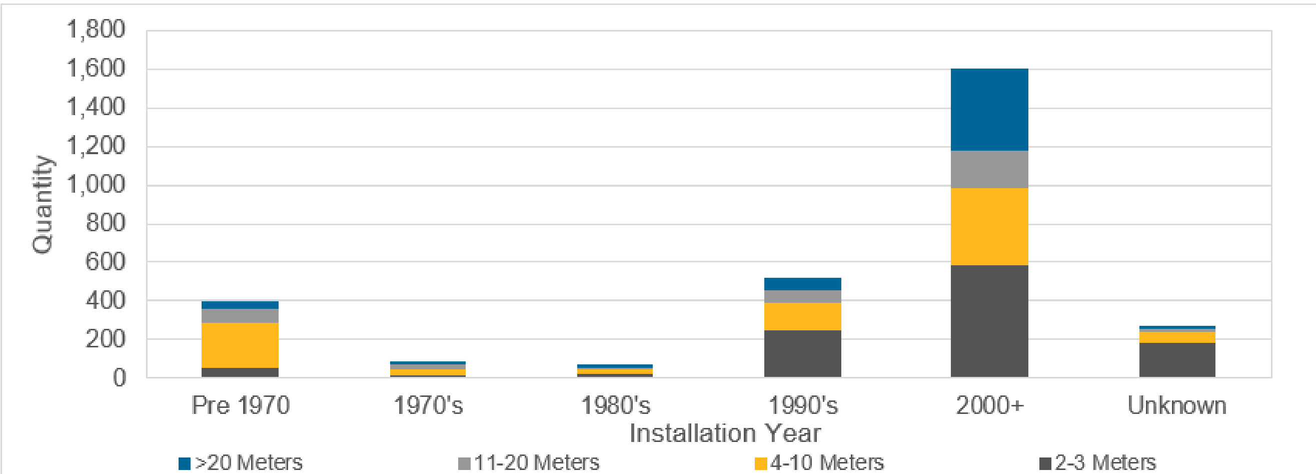


Figure 5.2-94: Multi-Family Installations Vintage Distribution and Meter Quantity at Each Site – EGD Rate Zone

This inspection program focuses on two main condition categories which 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

5.2.5.7.2.2 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 EGI's Integrity Program.

5.2.5.7.2.3 Risk and Opportunity

The risks associated with Multi-Family Buildings Services are the same as the Service Extensions (see **Section 5.2.5.7.1.3**).

Additional risks associated with Multi-Family Buildings include:

- Installation standards allow for these buildings to have higher-pressure gas than a single-family residential unit.
- Unit density means potential incidents can have a greater impact. Loss of containment will impact more people, resulting in a greater probability of personal injury.
- If internal piping is in poor condition, improper physical support 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.

The historical frequency of incidents related to multi-family building services is low. 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 operational risk includes customer service disruptions and media coverage which may result in reduced customer confidence in EGI. Environmental risks include GHG emissions and environmental impact of a leak. EGI continues to take steps to gather necessary information and better manage these assets and their risks.

5.2.5.7.3 BULK METER HEADERS

Properties that may include many premises utilizing natural gas that are served through a common meter, where the meter measures the consumption of all premises collectively are considered Bulk-Metered sites. A bulk meter header is a configuration consisting of one Sales Meter Only (SMO) or a Sales Station and its associated piping, that provides one measured gas consumption to a property that has several civic addresses within its boundary. 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 premises. Examples include:

- Residential Social Housing Development
- Farms equipped with multiple crop-dryers
- Academic, assembly, industrial and military campuses

An example of this type of configuration is shown in **Figure 5.2-95**. Note that the piping downstream of the bulk meter operates at intermediate pressure, the same pressure as the gas main serving the bulk meter and can be EGI-owned or customer-owned.

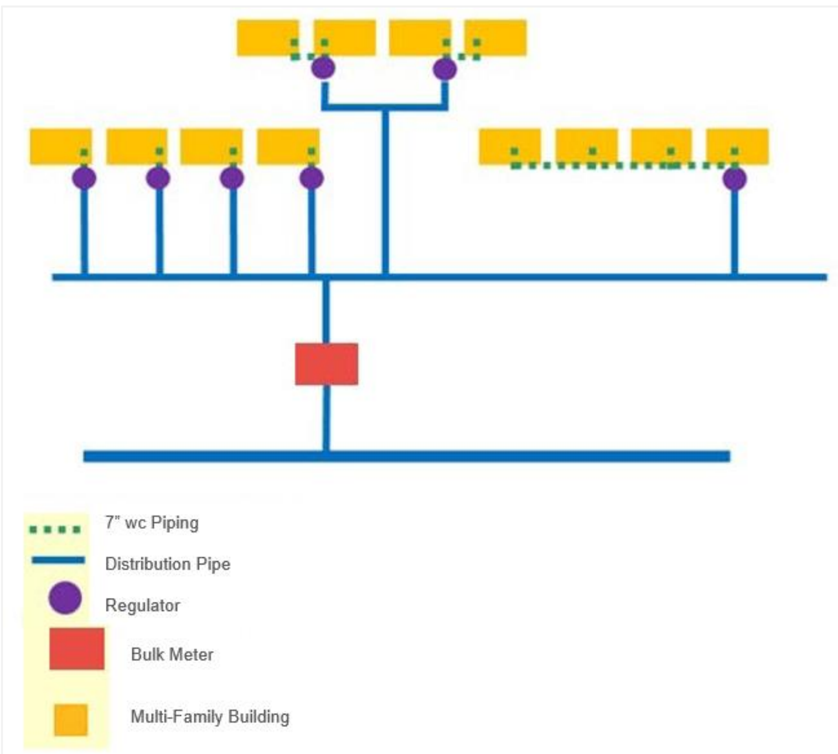


Figure 5.2-95: Bulk Meter Header Sample Configuration

5.2.5.7.3.1 Condition Methodology

An EGD rate zone survey in 2019 found no remediations required at any sites where the downstream piping was owned by EGI. EGI's DIMP is planning to identify and survey the Union rate zones' Bulk Meter Heaters.

5.2.5.7.3.2 Condition Findings

Previous surveys indicate the most common condition issues found on bulk meter headers are:

- Lack of a clear demarcation point between company and customer assets
- Presence of obsolete regulators 20 years and older
- Nonadherence to current installation and maintenance specifications (records, leak and corrosion surveys)
- Vent clearances and configurations not consistent with current standards, not all fittings above ground and evidence of obsolete components

5.2.5.7.3.3 Risk and Opportunity

Historically, the probability of failure is low for these assets. However, bulk meter sites can have higher consequences if failure does occur since the buildings serviced are higher-density 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. The operational risk includes customer service disruptions and media coverage resulting from these events may result in reduced customer confidence in EGI. Environmental risks include GHG emissions and environmental impact of a leak. EGI continues to take steps to gather necessary information and better manage these assets and their risks.

As noted above, there is ongoing work to identify bulk meter sites, assess their condition, and remediate as required; ensuring these locations are safe and provide reliable service to customers. Compliance with existing EGI policies on these assets keeps the safety risk low. The current process for assessing and remediating bulk meter sites provides continuous improvements and ensures the risk remains low.

5.2.5.8 Customer-Owned Systems

Customer-owned systems, as described in **Section 5.2.5.1**, may consist of:

- **Customer-owned piping** refers to the gas piping or tubing downstream of the meter outlet tailpiece and extending from the meter outlet to customer appliances.
- **Service jumpers** refer to a specific type of customer-owned pipe installed from an outside meter to inside the building, entering the building belowground.
- **Customer appliances** refer to gas appliances using gas delivered by EGI and 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 facilities 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.

Regarding supply of gas, EGI must comply with *Gaseous Fuels O. Reg. 212/01*, *s. 16*, which states:

> No distributor shall supply gas to a premises unless the distributor is satisfied that the installation and use of the appliance or work comply with this Regulation and,
>
> (a) unless the distributor has inspected the appliance or work at least once within the previous 10 years; or

(b) unless the distributor has inspected the appliance or work in accordance with a quality assurance inspection program. O. Reg. 212/01, s. 16.

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.

5.2.5.9 Utilization Strategy Outcomes

5.2.5.9.1 METER PURCHASES

The maintenance strategy for meters is to continue with the current MXGI Program and managing non-program meter exchanges. The joint Measurement Canada accreditation for EGD and Union 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.
- For >400 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 to 20 years
  - Modules: 10 to 12 years
  - Turbine meters: 6 years
  - Instruments: 7 to 12 years
- EGI reactively responds to customer leak or other service interruption calls for non-program related meter exchanges.

5.2.5.9.2 MXGI PROGRAM (METERS)

The **Meter Exchange Government Inspection (MXGI) Program** is designed to replace meters before they fail. Meter seal life and extensions are based on sampling and testing to ensure Measurement Canada specifications are maintained. EGI continues to use data to project Out Of Date (OOD) 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.

This replacement program is mandated by Measurement Canada, which maximizes asset life through sampling and testing (MXGIs), to ensure the required level of metering accuracy. The projections for 2023 to 2032 are shown in **Table 5.2.5-7** and **Table 5.2.5-8** for the EGD and Union rate zones respectively.

Table 5.2.5-7: Meter Replacements (Projected) – EGD Rate Zone

Year	Meter Exchanges (Program)	Non-Program Meter Exchanges
2023	88,474	18,776
2024	89,359	18,964
2025	90,252	19,153
2026	91,155	19,345
2027	92,066	19,538
2028	92,987	19,734
2029	93,917	19,931
2030	94,856	20,130
2031	95,805	20,332
2032	96,763	20,535

Note: Meter Exchanges (Program) include both OOD and MXGS.

Table 5.2.5-8: Meter Replacements (Projected) – Union Rate Zones

Year	Meter Exchanges (Program)	Non-Program Meter Exchanges
2023	53,582	8,769
2024	54,278	8,883
2025	54,984	8,998
2026	55,699	9,115
2027	56,423	9,233
2028	57,156	9,353
2029	57,899	9,475
2030	58,652	9,598
2031	59,414	9,723
2032	60,187	9,849

Note: Meter Exchanges (Program) include both OOD and MXGS.

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 was 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.

5.2.5.9.3 ADVANCED METER INFRASTRUCTURE PILOT

EGI is considering the deployment of Advanced Metering Infrastructure (AMI), which would modernize customer meters and allow two-way communication. AMI is expected to provide significant benefits to customers, reducing meter reading and call centre costs and eliminating estimated bills, while providing customers insight into their gas usage so they can make informed decisions. In the 2024 Rate Rebasing Customer Engagement, the majority of customers support the installation of AMI in order to achieve the enhanced benefits, even at an impact to their rates as a result of the implementation. With access to granular usage information, EGI gains needed insights into peak consumption and usage patterns. This will support EGI's implementation of an Integrated Resource Planning (IRP) alternative program and may allow the deferral of reinforcement projects and promote carbon reduction. An AMI pilot project is currently underway; as results are received from the pilot, the scope of the AMI Program will be clearly defined and incorporated into future Asset Management Plans as required. For more detail on EGI's AMI strategy, refer to Exhibit 2, Tab 7, Schedule 2.

5.2.5.9.4 MXGI PROGRAM (REGULATION)

The strategy is to continue exchanging assets identified with 200 & 400 Series Meters in conjunction with the MXGI Program (Meters). The strategy corrects other compliance issues as part of the MXGI Program, as these critical assets serve the majority of customers in the EGI franchise area. This strategy applies a planned and controlled spend of capital dollars, while maintaining the current level of operational reliability.

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 through the Regulator and External Relief Valve Information Gathering 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, analyzing asset life cycle, and assessing risk.

5.2.5.9.5 TARGETED INSPECTION AND REMEDIATION STRATEGY

The Targeted Inspection and Remediation Strategy is used to remediate high-priority condition issues identified through EGI's DIMP. Through the DIMP, surveys collect information on the failure rates of assets, informing future policy decisions on replacement frequency.

This proactive 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. 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. This aligns with the feedback from the 2024 Rate Rebasing Customer Engagement Survey on replacing pipelines and equipment as the majority of customers indicated a preference for EGI to assess the long term health of the system and to spread out costs over time (even if that means higher rates now).

5.2.5.9.6 CONTINUE EXISTING PRACTICES AT INSTALLATION (CUSTOMER-OWNED SYSTEMS)

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 & 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.

5.2.5.9.7 OPPORTUNISTIC REPLACEMENT

The opportunistic replacement strategy looks to replace regulator sets, internal piping configurations and Service Extensions in conjunction with planned and unplanned adjacent work scheduled, such as planned city sidewalk/road replacements. Regulator sets are opportunistically replaced if found to be 20 years or older. 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.

5.2.5.10 Utilization Capital Expenditure Summary

The total average capital spend is forecast to be $163M (EGI) as summarized in **Table 5.2.5-9**. The Utilization capital is further summarized as part of EGI's total 10-year capital plan in **Section 6**.

Table 5.2.5-9: Utilization Capital Summary ($ Millions) – EGI[18]

Asset Class Strategy	Program Name	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-Year Forecast
Meter Purchases	Meters (growth)	11.9M	12.2M	12.3M	12.2M	12.7M	12.2M	11.8M	11.8M	11.3M	10.6M	119.0M
	Meters (mtc)	58.6M	66.8M	66.2M	68.3M	74.2M	75.3M	76.5M	80.7M	81.7M	81.1M	729.3M
AMI Pilot	Monitoring Systems	1.9M	-	-	-	-	-	-	-	-	-	1.9M
MXGI Program	Regulator Refit	62.7M	66.1M	68.2M	70.7M	77.0M	78.2M	79.6M	84.2M	85.3M	84.8M	756.8M
Targeted Inspection and Remediation Program	Remediation	1.0M	1.0M	1.4M	1.5M	1.7M	1.9M	1.9M	2.0M	1.4M	1.3M	15.0M
Total		**136.5 M**	**146.5 M**	**148.5 M**	**153.2 M**	**166.3 M**	**168.4 M**	**170.5 M**	**179.5 M**	**180.4 M**	**178.6 M**	**1628.3 M**

[18] Includes overhead allocation

5.3 Storage and Transmission Operations

EGI's Storage and Transmission Operations (STO) asset classes consist of a system 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 1,500 km of transmission and storage pipelines. EGI has storage and transmission assets that serve to receive, store and transport natural gas to major demand markets in Ontario, Québec, Maritimes, Michigan, and the U.S. Northeast. EGI's Dawn Hub, located 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.

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, transport it to and store it at Dawn, and have it withdrawn and delivered when and where needed. Dawn is one of the 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 in and out of underground storage reservoirs and into and through the transmission systems. Gas compressors are used to transport gas into and through the transmission systems and can be configured for the high flow rates required. Gas compressors are also used to move gas in and out of underground storage reservoirs by providing the high-pressure differential required to fill and empty the pools. The use of subsurface 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 (MOP), cushion pressure and the size of the pool. Through EGI's reservoirs, the total storage working inventory is approximately 311 petajoules (PJ) (199 PJ regulated and 112 PJ unregulated). Each reservoir is protected by a Designated Storage Area (DSA) which is determined by EGI and approved by the Ontario Energy Board 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. Dawn is the largest underground storage facility in Canada and a key natural gas trading hub that has interconnections to various transmission pipeline systems including Vector, TC Energy, Tecumseh Gas Storage and Panhandle Eastern Pipeline through the EGI Panhandle Transmission System. The stations include 20 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.

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 as set out in *General Terms and Conditions*. 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.

EGI operates one 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 served from the TC Energy Canadian Mainline. As an integrated storage and transmission system operator, EGI requires reserve capacity to support the integrity of the system and the provision of service to all customers. The Hagar facility provides this reserve capacity that ensures reliable supply through EGI's storage, transmission and distribution systems during peak demand periods. The Hagar station is used to support the Sudbury Lateral System during peak demand periods, supply shortfall, unplanned low system pressures or pipeline outages. The station served this purpose in 2011 during a TC Energy Canadian Mainline pipeline rupture near Beardmore, Ontario.

5.3.1 Storage and Transmission 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. The objectives in **Table 5.3.1-1** are in addition to the system integrity, reliability and compliance objectives for the Distribution Pipe, Distribution Stations and Utilization asset classes.

5.3.1.1 Transmission System Objectives

Dawn Parkway Transmission System

The Dawn Parkway Transmission System is composed of up to four parallel 26-, 34-, 42- and 48-NPS pipelines and compressor, metering and regulating stations running from the Dawn Hub easterly toward the Greater Toronto Area (GTA), terminating at the Parkway compressor station, Lisgar gate station and Albion custody transfer station. This system has four major compressor stations (Dawn, Lobo, Bright and Parkway) to facilitate transport as shown in **Figure 5.3-1**.

The primary purpose of this system is to transport natural gas easterly from Dawn to Parkway and to Albion. The system serves both in-franchise regions along the route (GTA West, Southeast and portions of the Southwest regions) and ex-franchise transportation customers (gas moving between receipt and delivery points on the system).

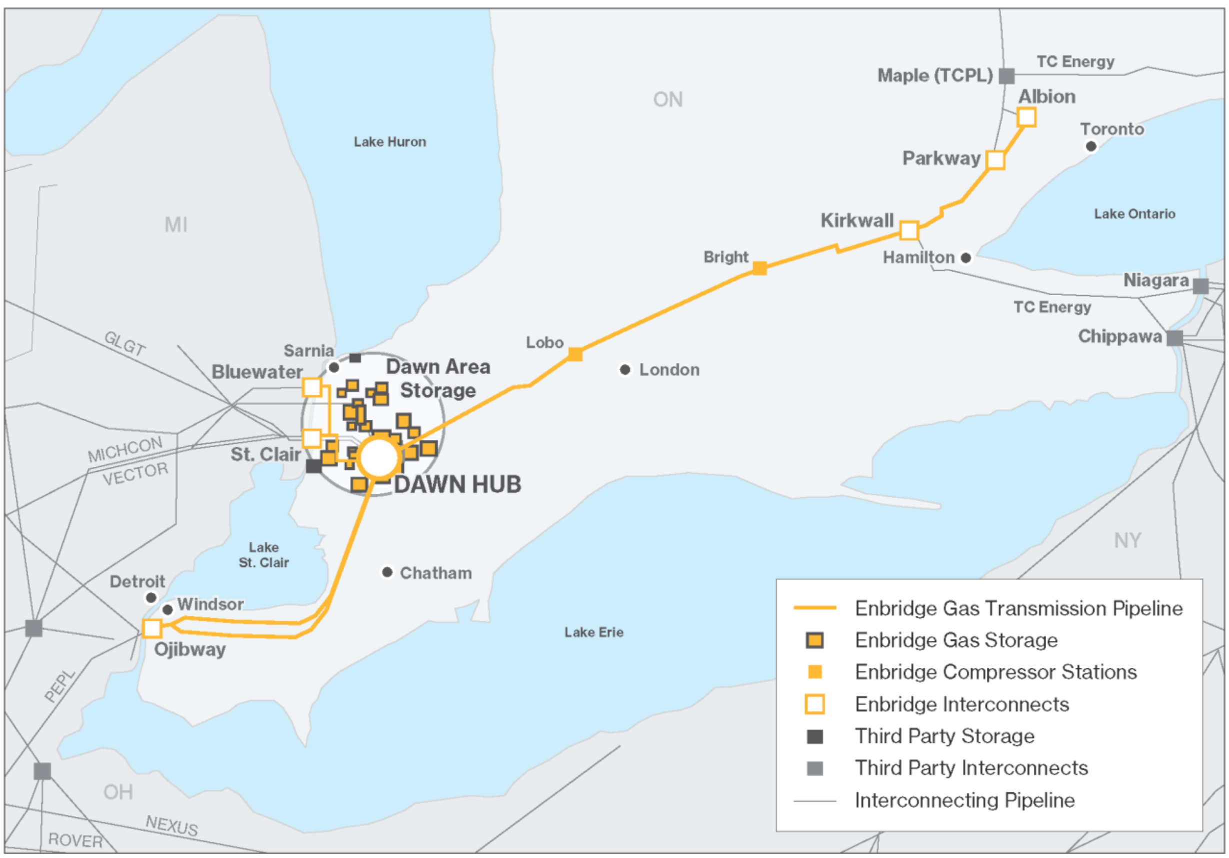


Figure 5.3-1: EGI Dawn to Parkway System

Panhandle Transmission System

The Panhandle Transmission System is composed of two 16-, a 36-, and a 20-NPS pipelines and metering and regulating stations running westerly from the Dawn Hub towards Windsor, terminating at the Ojibway River crossing where it interconnects with the Panhandle Eastern Pipeline system located in Michigan. Laterals which carry transmission system pressure into the Leamington/Kingsville market 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 serve in-franchise markets in a portion of the Southwest region including the Windsor/Essex, Chatham-Kent and southern Lambton County. It also transports gas for ex-franchise transportation customers from the Panhandle Eastern Pipeline to the Dawn Hub.

Sarnia Industrial Line Transmission System

The Sarnia Industrial Line (SIL) Transmission System is composed of a series of parallel 12- to 20-NPS 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 Hub to the SIL and NPS 20 pipelines run from Payne Pool to the SIL.

The primary purpose of this system is to transport natural gas from the Vector and Great Lakes Gas Transmission pipelines at the Courtright Stations, DTE Energy (via St. Clair Pipelines L.P.) at St. Clair Line station, Bluewater pipeline (via St. Clair Pipelines L.P.) at Bluewater Interconnect and Dow A Pool and Dawn to the gas distribution system, serving a portion of the Southwest region located in the northwest portion of Lambton County. It also transports gas for ex-franchise transportation customers from the DTE Energy (St. Clair) and Bluewater pipelines to the Dawn Hub.

Table 5.3.1-1 shows a summary of transmission system requirements and the objectives for each system.

Table 5.3.1-1: 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.
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.	No LCU at Sandwich Transmission Station. Maintain the required LCU capability at Dawn station to support Panhandle.	N/A
Measurement	Measure accurately all flow in and out.	Measure accurately all flow in and flow out at major stations.	Measure accurately 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. • Allow for ongoing inspection with minimal customer disruptions.		
System Growth	• System design and maintenance must consider future system growth implications. • Screen transmission system projects using the IRP Assessment Process; for those that pass, determine if there are IRPAs that are economically and technically feasible. • Ensure EGI provides new or upgraded natural gas services to residential, apartment, commercial, industrial and transmission customers – safely, and reliably while evaluating all energy solution alternatives as part of the IRP Assessment process.		

<table>
<tr><th>Requirement</th><th>Dawn Parkway</th><th>Panhandle</th><th>Sarnia Industrial Line</th></tr>
<tr><td>Integrated Resource Planning</td><td colspan="3">• Screen projects using EGI’s IRP Assessment Process; for those that pass, determine if there are IRPAs that are economically and technically feasible.</td></tr>
</table>

5.3.1.2 Underground Storage Objectives

The Underground Storage System is largely situated in the area surrounding the Dawn Hub in Lambton County in Southwestern Ontario. Storage is split into regulated and unregulated businesses, with a total working inventory of approximately 311 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 311 PJ of natural gas storage (199PJ regulated and 112 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 fill and empty the storage system more efficiently and increasing design day deliverability.
  - 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.

5.3.1.3 Liquefied Natural Gas System Objectives

The Liquefied Natural Gas (LNG) System’s primary purpose is to supply natural gas to support the Sudbury Lateral System during peak demand 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 lateral system market for approximately five to seven days. The objectives of the LNG System are as follows:

- Targeted full nominal capacity of 658 TJ by December 1 annually
- Provide up to 10 TJ of Peak Day supply in the Union Northern Delivery Area which reduces EGI’s need for other services
- Targeted daily tank vapourization capability up to 100 TJ deliverability (for injection into the Sudbury Lateral System) to meet system integrity requirements
- 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

5.3.1.4 Performance Measures

The performance measures for the STO asset classes are as follows:

- Greenhouse gas (GHG) emissions reduction (measured in fugitive emissions and fuel consumption reporting)
- Damages – first-, second-, and third-party line breaks per 1,000 locates
- Compliance rate of Inspections and Maintenance
- Work management process conformance
- Capital portfolio management delivery to plan
- Reliability percentage for transmission compression
- Percentage of successful compressor starts

- Compressor availability

To achieve the STO asset class objectives, asset investment decisions are governed by the life-cycle management strategies outlined in **Table 4.1-1**.

5.3.2 Storage and Transmission Asset Class Hierarchy

The subclass breakdown for STO is organized by system and illustrated in **Figure 5.3-2**.

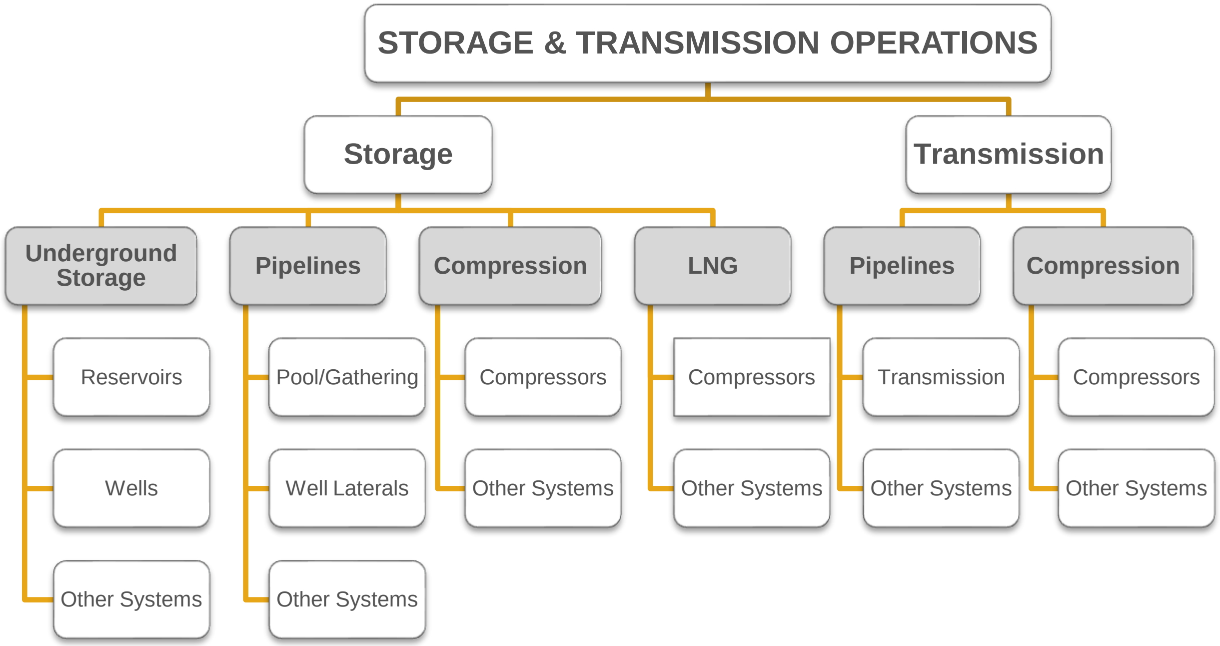


Figure 5.3-2: STO Hierarchy

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 include components such as dehydration systems, filters, separators, heat exchangers, fans and pumps.
  - Electrical systems include components such as breakers, switchgear, motor control centres and lighting.
  - Safety and Controls systems include components such as control valves, regulation, telemetry, PLCs, instrumentation, relief valves and fire and gas detection systems.
- **Pipelines** and **Underground Storage** assets include pipe, well casings and valves

5.3.3 Storage and Transmission Asset Inventory

The asset inventory for STO is listed in **Table 5.3.3-1**.

Table 5.3.3-1: STO Asset Inventory

Asset Subclass	EGD Rate Zone	Union Rate Zones
Compression (#)[19]		
Compressors	14	39
Dehydration (#)[20]		
Dehydration Systems	1	3
Underground Storage (#)[21]		
Reservoirs	11	25
Wells	129	230
Pipelines (km) [22]		
Transmission	120	1282
Storage	22	30
LNG (#)[23]		
Compressors	N/A	3

Note: Pipe inventory is also accounted for in the Distribution Pipe asset class (see **Section 5.2.3**).

[19] As of December 2021.
[20] As of December 2021.
[21] As of December 2021.
[22] As of Q1 2022.
[23] As of December 2021.

5.3.4 Storage and Transmission Operations Condition and Strategy Overview

Table 5.3.4-1: STO Operations Condition and Strategy Overview

Asset Subclass	Ave. Age (Year)	Condition	Risk / Opportunity	Maintenance Strategy	Replacement / Renewal Strategy
Compression **Dehydration** **Liquefied Natural Gas (LNG)**	32 30 54	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 Health and Safety Risk / Public Health and Safety Risk**: The safety risk related to loss of containment from the compressor units is considered. 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. **Reputational Risk:** 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. **Carbon Reduction Opportunity:** EGI continues to evaluate and implement facility emission reduction opportunities contributing to EGI's carbon reduction targets. The enterprise-wide carbon reduction targets are based on the Pan-Canadian Framework on Clean Growth and Climate Change.	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) and control systems is ongoing.	The renewal strategies for compressors, dehydration units and LNG assets are as follows: • Overhauls as recommended by the OEM (hour-based) • Overhauls recommended by SMAs based on condition findings • Planned obsolescence based on design life, industry intelligence 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 Health and Safety Risk / Public Health and 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. **Carbon Reduction Opportunity:** EGI continues to evaluate and implement facility emission reduction opportunities contributing to EGI's carbon reduction targets. The enterprise-wide carbon reduction targets are based on the Pan-Canadian Framework on Clean Growth and Climate Change.	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*	The renewal strategies for wells are as follows: • Relining of wells based on condition findings • Drilling new wells to replace lost deliverability of abandoned wells • 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 5.2.3.2**. The overview of strategy for transmission pipelines reinforcement is discussed in **Section 5.1.4**.				

5.3.5 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 rates; while in underground storage compression, it provides the high pressure differential required.

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 5.3-3**). Multiple independent compressor units are located at each station and used in various combinations to manage seasonal and weather-dependent system flow demands.

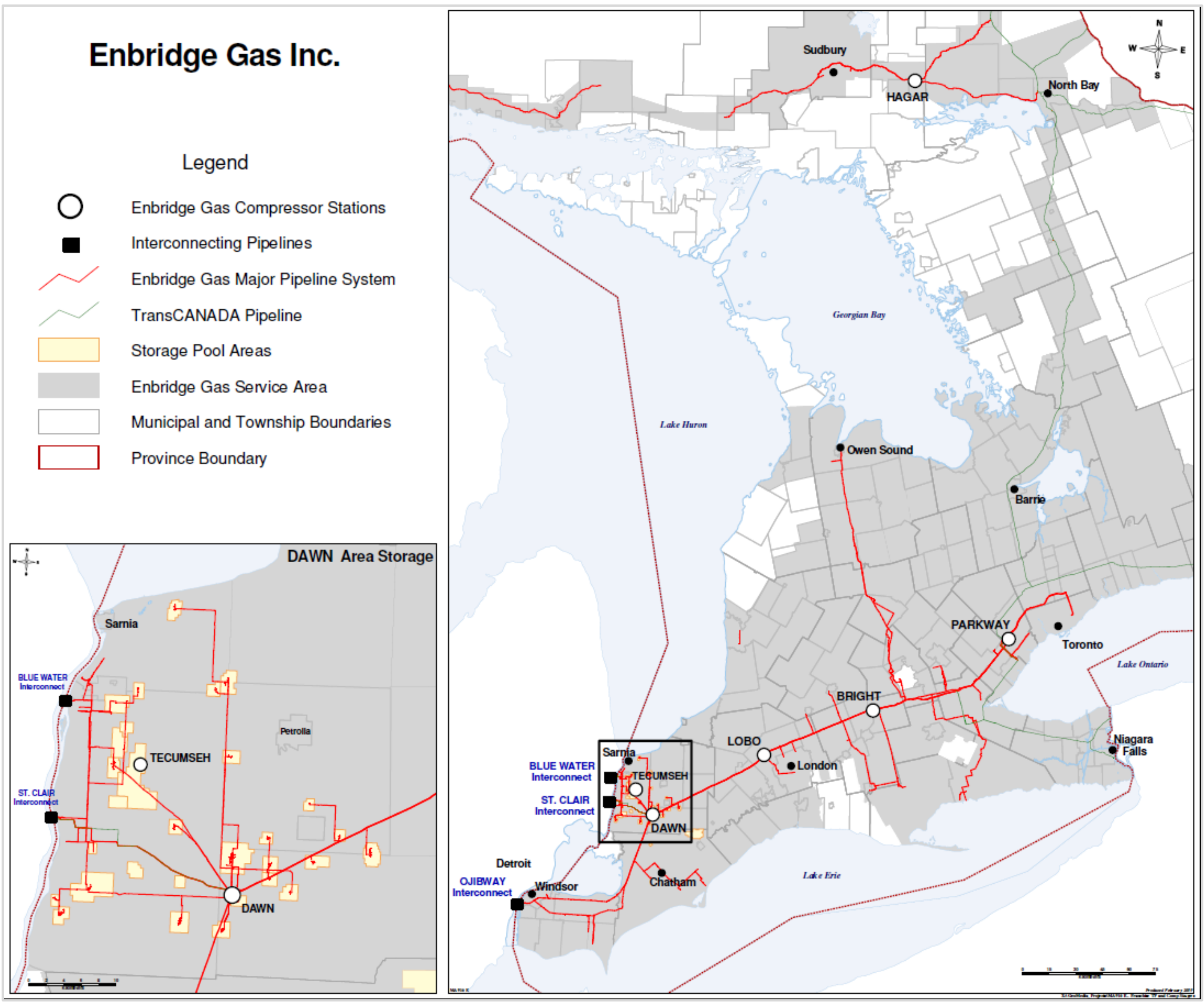


Figure 5.3-3: Compressor Stations in the Dawn to Parkway Transmission System

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 of EGI's compressors are natural gas-fueled and are comprised of both centrifugal and reciprocating (both integral and separable models) compressors with 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 daily fluctuating system demands. Failures are influenced by service conditions (operating hours) and the design life expectancy of components. Some key components are wear items which require regular inspection to establish wear tolerances and are replaced as needed.

Compressor packages are comprised of several subsystems, 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 5.3.5-1** lists the inventory at each compressor station.

Table 5.3.5-1: 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 systems and loss-of-critical-unit coverage for the Dawn Parkway System and the Panhandle 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 TC Energy Canadian Mainline.
Parkway West Compressor Station	2	Provides required delivery pressure and acts as a custody transfer station to TC Energy Canadian Mainline 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. **Note:** 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	13	Supports storage injections and withdrawals. **Note:** Daily winter flows are transported to market via the Dawn Parkway System, Sarnia and Panhandle.
Hagar Liquefied Natural Gas Station	2	Supports the Sudbury Lateral System during peak period demand and provides additional compression as required to maintain system pressure.
Iroquois Falls Compressor Station	1	Supports required delivery pressure for an industrial plant in Iroquois Falls.
Blowdown Recovery Compressors (Dawn, Lobo, Bright and Parkway West)	4	These units reduce the volumes of gas vented to atmosphere during planned compressor and yard blowdowns.

5.3.5.1 Condition Methodology

Engine and compressor condition is primarily maintained through a preventive maintenance (PM) program comprised of rigourous inspections and renewals via overhauls based on manufacturer recommended intervals. As it relates to compressors, condition refers to the ability of an asset to perform its intended function reliably and cost-effectively. 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. Online monitoring provides protection via control systems and is supported by control room operators responsible for recognizing changing conditions and reacting in near real time. 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 SMAs. As asset condition and performance degrade, risks are raised through the risk management process.

For components managed via an overhaul strategy, condition is viewed as a sawtooth function (see **Figure 5.3-4**). Condition degrades over the recommended overhaul interval and increases suddenly after an overhaul. **Figure 5.3-4** 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.

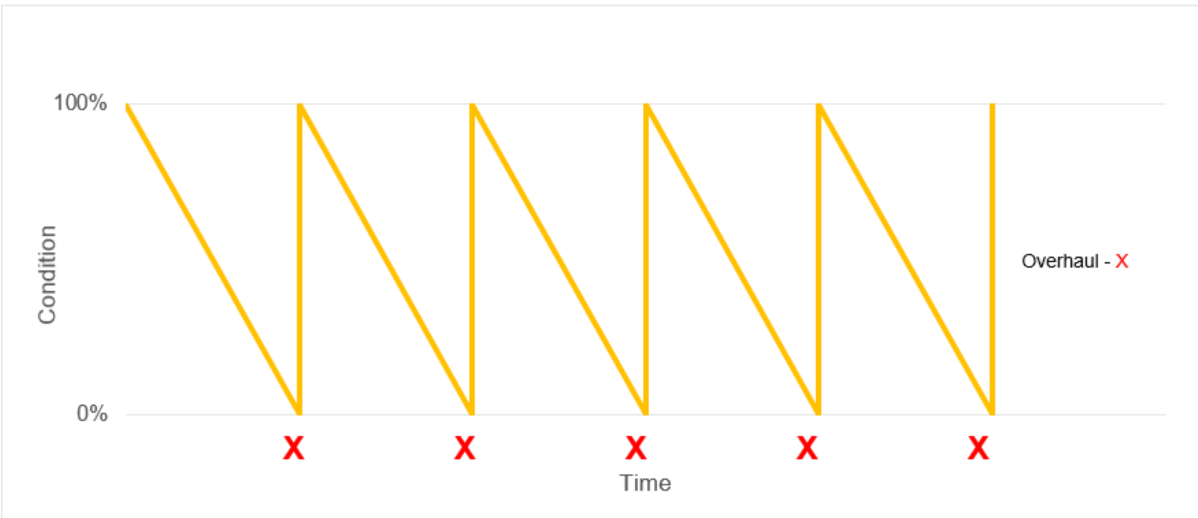


Figure 5.3-4: Condition Based on Overhauls

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. Subject matter advisors were then consulted to define and quantify the effect of failure-influencing factors. A condition status was assigned to 7 key reciprocating gas compressor sub-assets, based on a conditional reliability metric (at least one sub-asset failure will occur within a 2,000-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 EGD and Union 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 requires mitigation; 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 poses the risk of price volatility, especially during peak operation. In the 2024 Rate Rebasing Customer Engagement, the majority of customers indicated that EGI should replace compressor stations to reduce the risk of price volatility and avoid reliability and gas quality problems, with the understanding that there would be an associated increase to their bill.

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, and air compressors) 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.

Dehydration systems are subsystems within compression stations 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**.**

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 plan to proactively replace.

Federal methane regulations are a compliance requirement that came into effect January 1, 2020, with the purpose of reducing methane emissions from the oil and gas industry through leak detection and repair (LDAR) requirements, venting limits and equipment level emission limits. Targeted leak inspections at compressor stations, storage measurement stations and transmission receipt/metering stations are completed three times per year. Any required leak repairs are to be completed within 30 days or during the next planned shutdown. The shutdown must be scheduled prior to the point where the volume of gas saved by repairing the leak exceeds the volume of gas that must be vented from the pipeline in order to safely repair the leak.

Additionally, annual direct measurement or continuous monitoring of compressor seal and rod packing emissions is required, with similar repair timelines requirements. Corrective action must be completed within 90 days or the next shutdown, with the shutdown scheduled prior to the point where the volume of gas saved by repairing the leak exceeds the volume of gas that must be vented from the pipeline in order to safely repair the leak.

As of January 1, 2023, federal methane regulations will also require any continuous or high bleed pneumatic device be replaced with a Low or No-bleed device. An application for an exemption from the limit may be made for individual pneumatic devices based on safety or operational needs.

Facility venting limits will also come into effect on January 1, 2023 and will apply to designated stations within EGI's storage and transmission operations. All venting volumes will have a requirement to be calculated and tracked on a monthly basis, regardless of whether the venting activity is exempt from the venting limit. Vented activities exempted from the facility venting limit include blowdowns, glycol dehydration, pneumatics, start-ups/shutdowns, and emergency venting.

5.3.5.2 Condition Findings

Overhauls are based on current run hours, annual usage forecast and manufacturer recommended overhauls. 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 2023 is shown in **Figure 5.3-5**.

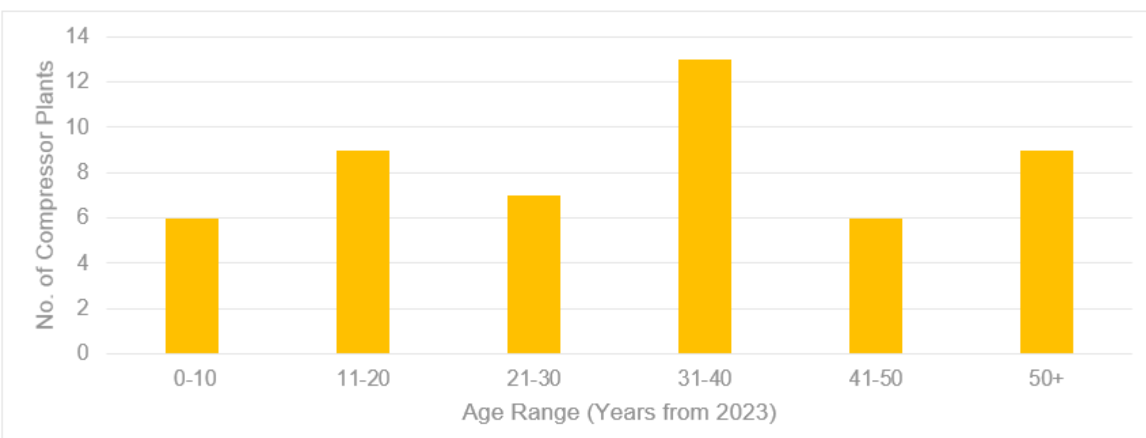


Figure 5.3-5: Age Range of Compressor Plant Installation

Asset age is used as a guideline to trigger detailed discussions with the OEM regarding their plan to support assets is critical in understanding the risk associated with continued operation of aging machinery. Discussions with the OEM and aftermarket suppliers for compressor units have indicated the components for various models are becoming obsolete. As the global inventory of spare parts is depleted, failures will need to be addressed with custom manufactured components.

Several compressors may become exposed to obsolescence risk over the next 10 years. With 15 compressor units exceeding 50 years of age within the next 10 years the risk of declining reliability and parts availability issues that the K701, K702, K703, and Waubuno compressors are experiencing today is increasing.

Table 5.3.5-2 shows the findings from the AHR assessment for compressors at the Corunna Compressor Station.

Table 5.3.5-2: 2021 Storage Asset Health Index (over a 2,000-hour mission time)

Unit#	2021 Storage Asset Health Index (over a 2000 hr mission time)						
	Foundation	Crankshaft	Engine	Compressor	AfterCooler	Heating & Cooling System	Valving System
K701	SHI2 (5000-10000hrs)	SHI2 (5000-10000hrs)	SHI5 (<=2200hrs)	SHI5 (<=2200hrs)	SHI3 (3000-5000hrs)	SHI4 (2200-3000hrs)	SHI4 (2200-3000hrs)
K702	SHI1 (>10000hrs)	SHI2 (5000-10000hrs)	SHI5 (<=2200hrs)	SHI5 (<=2200hrs)	SHI3 (3000-5000hrs)	SHI4 (2200-3000hrs)	SHI4 (2200-3000hrs)
K703	SHI1 (>10000hrs)	SHI2 (5000-10000hrs)	SHI5 (<=2200hrs)	SHI5 (<=2200hrs)	SHI3 (3000-5000hrs)	SHI4 (2200-3000hrs)	SHI4 (2200-3000hrs)
K704	SHI3 (3000-5000hrs)	SHI2 (5000-10000hrs)	SHI3 (3000-5000hrs)	SHI4 (2200-3000hrs)	SHI3 (3000-5000hrs)	SHI4 (2200-3000hrs)	SHI4 (2200-3000hrs)
K705	SHI1 (>10000hrs)	SHI1 (>10000hrs)	SHI4 (2200-3000hrs)	SHI5 (<=2200hrs)	SHI3 (3000-5000hrs)	SHI4 (2200-3000hrs)	SHI4 (2200-3000hrs)
K706	SHI1 (>10000hrs)	SHI1 (>10000hrs)	SHI4 (2200-3000hrs)	SHI5 (<=2200hrs)	SHI3 (3000-5000hrs)	SHI4 (2200-3000hrs)	SHI4 (2200-3000hrs)
K707	SHI1 (>10000hrs)	SHI1 (>10000hrs)	SHI4 (2200-3000hrs)	SHI5 (<=2200hrs)	SHI3 (3000-5000hrs)	SHI4 (2200-3000hrs)	SHI4 (2200-3000hrs)
K708	SHI1 (>10000hrs)	SHI1 (>10000hrs)	SHI4 (2200-3000hrs)	SHI5 (<=2200hrs)	SHI3 (3000-5000hrs)	SHI4 (2200-3000hrs)	SHI4 (2200-3000hrs)
K709	SHI1 (>10000hrs)	SHI1 (>10000hrs)	SHI4 (2200-3000hrs)	SHI5 (<=2200hrs)	SHI3 (3000-5000hrs)	SHI4 (2200-3000hrs)	SHI3 (3000-5000hrs)
K710	SHI1 (>10000hrs)	SHI1 (>10000hrs)	SHI4 (2200-3000hrs)	SHI5 (<=2200hrs)	SHI3 (3000-5000hrs)	SHI4 (2200-3000hrs)	SHI4 (2200-3000hrs)
K711	SHI1 (>10000hrs)	SHI2 (5000-10000hrs)	SHI3 (3000-5000hrs)	SHI4 (2200-3000hrs)	SHI3 (3000-5000hrs)	SHI4 (2200-3000hrs)	SHI4 (2200-3000hrs)

- Crank assemblies experience an increasing misalignment rate over time. 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.
- 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.
- In general, compressors have the lowest reliability and asset health compared to other asset subclasses within compressor stations. As a result, compressor overhauls are required to maintain a required level of reliability.
- According to failure intensity results, glycol leaks (which seem to be a random type of event in heating and cooling systems) are the major failure modes in these systems as heating and cooling systems showed low-asset health conditions in compressor stations within the EGD rate zone.

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 informs future capital investment requirements. The FIMP is currently focused on the assessment of assets within compressor facilities, not inclusive of the compressors themselves.

5.3.5.3 Risk and Opportunity

The risks and opportunities are considered below in the Risk Categories that are relevant to EGI.

Operational Risk: The reliability of gas compressors is integral to managing operational risk and customer impact. Unplanned failures, especially during peak demand times, can have a highly disproportionate impact on gas supply costs.

Gas compressor reliability risk changes continuously during annual inventory turnover. In the early stages of the injection or withdrawal phases, compression is not required at all times to meet delivery requirements. The demand on units, both in terms of individual units as well as the number of units, increases steadily and reaches 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 can be 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-favourable market conditions. Short duration outages can happen regularly; however, long-term outages are much less frequent.

The inability to maintain EGI obligation of 4 lb H20/MMscf under the *General Terms and Conditions* can impact firm service to all distribution customers, the storage and transmission system and third-party storage providers. Through assessment of contractual moisture-content obligations of interconnecting pipelines and modelled moisture content, if EGI experiences increased demand on the transmission system, incremental dehydration facilities would 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

Environmental Risk: Dehydration systems can experience a failure that would result in a spill of triethylene glycol (TEG) to the environment. The likelihood is greater at manually operated locations and in systems containing single-walled tanks.

Employee and Contractor Health and Safety Risk / Public Health and Safety Risk: The current risk due to the potential accidental release of natural gas at the Corunna Compressor Station (CCS) is exposing individuals to risks above EGI's individual upper threshold for workers. The maximally exposed individual at the site is Operations – Op. 2 Plant. The following individuals are exposed to risks above EGI's individual upper threshold for workers:

- Operations – Op. 2 Plant
- Mechanics
- Instrumentation
- Electrical
- Chief Mechanic

The greatest potential for loss of life at the CCS is concentrated in compressor buildings 1, 2 and 3. The greatest contributing scenarios to the results of the Quantitative Risk Assessment (QRA) include: (1) potential leaks from compressors and associated indoor piping finding a potential source of ignition and resulting in a potential flash fire or explosion and fatal accident, and (2) potential leaks from outdoor compressor header piping finding a potential source of ignition and resulting in a fire.

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).

Compressor failure introduces the risk of price volatility as it could require EGI to buy more gas on the market, rather than drawing gas from its storage. Furthermore, in the case of failure, construction could take multiple years to complete, extending the risks for longer.

Inability to maintain EGI's obligation of 4 lb H20/MMscf under the *General Terms and Conditions* 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.

Reputational Risk 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.

5.3.5.4 Compression Stations Strategy Outcomes

Detailed inspections at set frequencies, subsequent remedial activities and constant condition monitoring help identify abnormal 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, OEM recommendations and SMA review. Full replacement is generally based on design life, historical obsolescence and OEM equipment support.

The FIMP Strategy is described in the Distribution Stations asset class (see **Section 5.2.4.6.1.6**). The detailed strategies for compression include:

5.3.5.4.1 COMPRESSOR MODERNIZATION

As compressor units increase in age, they may no longer be supported by the OEM and the risk of not being able to find parts or expertise to repair the units increases significantly. If available, refurbished or custom parts can be used for repairs but may have reduced life expectancy. Custom components create a risk of the introduction of performance and functional issues when compared to those provided by the OEM if material composition or tolerances differ. Further, the cost of custom components can be more expensive and lead times for locating refurbished parts or machining custom pieces can lead to extensive increases in unit downtime and are reactive in nature.

The Compression Modernization Strategy aims to identify the top-risk compressor units both from a likelihood of failure (how soon) and consequence (how significant an outage is) perspective. End of life, driven by the risk of obsolescence, has highlighted that several units of the same vintage, make and model may become obsolete in a similar timeframe. Widespread replacement of multiple compressors at multiple sites in a short duration is not feasible based on operational and resource requirements.

In order to pace capital expenditures, resources and obsolescence risk over several years, EGI's approach is to stagger the related investments based on risk, location, model and OEM support. Customers indicated they support the pacing of EGIs compressor projects in the 2024 Rate Rebasing Customer Engagement.

The K701, K702 and K703 Ingersoll Rand, KVT model compressors were installed at the Corunna Compressor Station (CCS) in 1964. These 3 units account for 20% of the available compressor power at site. The lean-burn (low emissions) systems installed on the KVT compressor model (units K701 through K703) in the 1990s are rare as they represent a small number of units in the world of the particular model with the retrofit (KVTR). With the units having been in service for more than 50 years, the operational risks due to obsolescence and reliability are increasing.

The Joy Compressor (manufactured in 1985) was a used compressor package installed at Waubuno in 1988. The Joy Compressor Company changed ownership approximately 20 years ago whereupon OEM support for the compressor was discontinued. Although normal wear components are still available in the marketplace, replacement of critical items such as cylinders, crankshafts and rods are no longer available.

The recently abandoned reciprocating compressor unit at the Crowland Station was installed in 1970 and is comprised of a Waukesha engine and Ingersoll Rand compressor. The compression supported the Crowland Storage Pool on both injection and withdrawal. Due to the age of the facility, the compressor station did not conform to modern design standards and code requirements. The antiquated site design introduced risks related to process safety and obsolescence and there was limited ability to monitor and operate the site remotely.

There are 19 Siemens gas turbine-driven compressor units in the Gas Distribution and Storage (GDS) Dawn to Parkway compressor fleet. By continuing to follow the OEM-recommended maintenance schedules the units are expected to meet their seasonal operating requirements. Since the compressors are operated based on seasonal demand rather than a 24/7x365 continuous operation, they are expected to become obsolete before they come to end of life due to functional failure. Through discussions with the OEM, the engine models to consider as investments to manage obsolescence are the RB211-24A, RB211-24C and Avon.

- Siemens RB211 24A (1 unit) – There is one remaining RB211-24A gas turbine located at Dawn that was installed in 1982. The OEM of the Dawn C unit has indicated that due to a limited number of the RB211-24A model remaining in their global fleet, they will not be developing a long-term strategy to support obsolete components. As the inventory of engine parts required to recover from a critical engine failure or to complete recommended overhauls is decreasing and has been depleted for some components, the recommendation from the OEM is replacement.
- Siemens RB211 24C (5 units) – These units were installed over a period of several years, starting in 1989 and are located at Dawn, Lobo and Bright. EGI does not currently own a spare RB211 24C engine that can be employed in the event of an engine failure. As a result, a failed unit would have to be removed for offsite repair. In such cases, the use of the loss of critical unit (LCU) may be extended for more than the advised timeframe posing increased reliability

risk associated with the overall system demand. The OEM has communicated their recommendation is to upgrade to a newer model via component replacements at the next scheduled overhaul.

- Siemens Avon (3 units) – These units were installed over a period of several years, starting in 1971 and are located at the Lobo and Parkway compressor stations. Lobo A1 was installed in 1971 and Lobo A2 was installed in 1972. Bright A1 was installed in 1973 and Bright A2 was installed in 1975. Parkway A was installed in 1989. These units were interchanged between Lobo, Bright and Parkway depending on the system requirements (import, export and system load). As system loads grew, the output of an Avon plant (13.4 MW – 15.7 MW) was no longer adequate to support design day requirements and the Bright plants were chosen to be replaced by RB211 24G plants in 2008. At this time, a spare Avon engine has been purchased and can be exchanged with any of the three remaining units in operation. The indication from the OEM and aftermarket vendors is that support will continue until a new engine model with pollution controls is available. The strategy is to continue to overhaul the units as per their current schedule until such time the OEM informs that support will no longer be available.

The following investments have been identified to modernize the compressor fleet and address risks related to obsolescence, reliability, and process safety.

Dawn to Corunna

The K701, K702 and K703 compressor units account for 20% of the available compressor power at the Corunna Compressor Station (CCS) and their operating reliability is declining. Many of the reliability concerns stem from lean-burn conversions. During the mid-1990s, EGI embarked on an emissions abatement program, which retrofitted all units with low nitrogen oxide (NOx) combustion systems. The lean-burn (low emissions) systems installed on the KVT compressor model (units K701 through K703) are rare as they represent a small number of units in the world of that particular model with the retrofit. Indications from SMAs suggest there are only four lean-burn KVT units in the world, and EGI owns three of them. The KVT lean-burn conversion kits were not designed for mass production and have experienced a variety of problems.

With the units having been in service for more than 50 years, preventive maintenance and noncontinuous operation has maintained units; but reliability continues to decline. As failures become more frequent, technical support for existing compressors continues to decline as the industry has moved to different units resulting in higher costs and downtime to analyze, repair or modify compressors.

In addition to the obsolescence and reliability concerns associated with units K701, K702 and K703, the layout of the Corunna Compressor Station is comprised of 11 reciprocating compressors within 3 buildings adjacent to an above-ground header system.

The current risk due to the potential accidental release of natural gas at Corunna is exposing individuals to risks above EGI's individual upper threshold for workers. The greatest contributing scenarios to the result of this assessment include:

- Potential leaks from compressors and associated indoor piping finding a potential source of ignition and resulting in a potential flash fire or explosion fatal accident.
- Potential leaks from outdoor compressor header piping finding a potential source of ignition and resulting in a fire.

As environmental regulations become more stringent, the ability to meet standards with existing equipment specifications is becoming a challenge as environmental regulations were not accounted for as part of the original design. Modifying existing units for new emission targets with reduced technical support can be costly, success is uncertain and introduces risk of performance and functional issues associated with custom components that differ from those designed by the OEM if material composition or tolerances vary. Further, the cost of custom components can be more expensive and lead times for locating refurbished parts or machining custom pieces can lead to extensive increases in unit down time.

In review of the system requirements in their entirety, mitigation of the safety risk to individuals can be achieved by a single investment that also addresses the risks associated with compressor obsolescence and reliability. The recommended solution is to install 20 km of NPS 36 pipeline from Dawn to Corunna Compressor Station which includes the retirement and abandonment of compressor units K701, K702, K703, K705, K706, K707 and K708 while replacing the equivalent system design day storage capacity.

Life-cycle retirement of the seven compressor units creates the opportunity to avoid planned maintenance capital expenditures required to address risks associated with the following: pressure control and overpressure protection, foundation repairs, vibration detection equipment, valve replacements, glycol system upgrades, replacement of jacket water coolers, overhauls and cam upgrades. In addition to avoided capital expenditures, the abandonment of units K705 to K708 allows for critical spares to be retained to reduce the risk of extended downtime for the remaining compressor units associated with extended OEM lead times.

Appendix A, Pg. 1 provides additional detail on this investment.

Dawn to Corunna (Dawn Tie-In)

This portion of the project is specific to the Union Rate Zones to tie in the NPS 36 pipeline into the Dawn Yard. **Appendix A, Pg. 5** provides additional detail on this investment.

Crowland Station Renewal

Due to the age of the facility, the station experienced process safety concerns (lack of automation, unit valves, electrostatic discharge, dehydration and incinerator systems), obsolescence issues (compressor, building, and 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.

The recommended alternative is to rebuild Crowland to allow remote operation and offset the need for compression. The decommissioning/removal of compression and the resultant distribution station investment can be found in **Section 5.2.4.6.1**.

Waubuno Compression Life Cycle

The Waubuno compressor elevates available pipeline pressure to the Waubuno Pool MOP. 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 previously owned compressor package and installed at Waubuno in 1988. The Joy Compressor Company changed ownership approximately 20 years ago whereupon OEM support for the compressor was discontinued. Although normal wear components are still available in the marketplace, replacement of major compressor items such as cylinders, crankshafts and rods 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 only repair options. 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, the other internal damage was repaired through custom machining services.

In order to meet life-cycle needs for the Waubuno storage facility, it is recommended to construct a new NPS 20 pipeline from Waubuno to the Dawn to Corunna pipeline (~1.5 km). The new pipeline will eliminate the requirement for a remote compressor at Waubuno resulting in the abandonment of the compressor unit and supporting assets. The station modifications required for this solution include new control and measurement building, meter upgrades, new valves, and a filter/separator with a launcher and associated piping. The scope of the compressor abandonment includes removal of the compressor and associated equipment in the Compressor Building; removal of the NPS 8 compressor suction and discharge piping; removal of the aftercooler, filter and silencer; removal of all electrical wiring, control wiring and Supervisory Control and Data Acquisition (SCADA) communication wiring and panels associated with the compressor. The compressor building and foundation will also be removed. See **Appendix A, Pg. 7** for additional detail on this investment.

Dawn C Compression Life Cycle

Dawn C is one of the nine centrifugal compressors located at the Dawn Compressor Station. It is a multi-cased unit and can operate in a series or parallel configuration. The unit is designed to allow for intermediate pressure lift in the single case configuration and high pressure lift in the series configuration. In the later part of the withdrawal season, Dawn C is primarily used in the series configuration to lift from low-storage pressure levels to intermediate pressures. The intermediate pressure level is typically elevated further by other compression to reach the desired Dawn outlet pressure. Dawn C and Dawn 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 higher minimum inlet rating, Dawn C and D become very critical when reservoir pressure falls below 400 psig as it typically does late in the operational season.

Siemens, the OEM of the Dawn C compressor, has indicated that due to a limited number of the RB211-24A model remaining in the global fleet that they will not be developing a long-term support strategy for obsolete components. The availability of components required to recover from a critical engine failure or to complete recommended overhauls is essential in managing risk. Reliability risk is managed by following OEM-recommended Preventive Maintenance (PM) schedules and overhauls. It is controlled to moderate levels, but the risk increases gradually over the 25,000-hour recommended interval between overhauls.

Notably, the RB211-24A in Dawn C has dimensions which limit interchangeability with more modern editions of the RB211 without significant plant retrofits. The recommendation to address the obsolescence is replacement.

The recommended solution is to replace Dawn C with a combination of compressors with equivalent horsepower and operating range. This solution will resolve the obsolescence concern and will also support reductions in emissions and improvements in reliability. There are currently operational fit issues at Dawn in the winter and upsizing C-Plant will increase the problem. Based on the critical horsepower gap, the recommendation per the storage planning model is to address operational flexibility while still meeting design day requirements with the installation of two smaller plants. **Appendix A, Pg. 3** provides additional detail on this investment.

Obsolete Engine - RB211-24C Model

In the event of a failure to an RB211-24C unit, the engine would need to be removed from the berth for repair. The downtime of the unit is increased due to the lack of a spare engine. An outage extends the reliance on the LCU at the particular site for the duration of the repair.

The recommended solution is to modernize the engine at the time of scheduled overhaul to a model identified by the OEM that will be supported beyond the duration of the asset plan. This solution reduces the risk of extended downtime caused by a failure to a component that is no longer available. It reduces the obsolescence risk across the fleet by pacing the upgrades of the five RB211-24C units, improves system reliability and supports reductions in emissions obtained via new technology.

Four of the five remaining RB11-24C units are not scheduled for their overhaul within the next 10-years. In absence of a spare engine, EGI is investigating the market availability of a used RB211-24C to act as a spare that can be installed in the event of an unplanned outage requiring the unit to be removed from the berth for repair or upgrade. A spare engine or an engine exchange service is considered an appropriate control to manage the risk of extended downtime and is available for all other turbine models that support the Dawn to Parkway system. EGI will continue to engage with the OEM to understand the availability of components for the 24C and the risk associated with obsolescence.

5.3.5.4.2 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. 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.

5.3.5.4.3 FOUNDATION BLOCK REPLACEMENTS

The foundation blocks for the reciprocating compressors require replacement due to age, operating hours, oil contamination and condition (the engine block foundations are deteriorating). Without remediation, 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.

5.3.5.4.4 VALVE REPLACEMENTS

Leaking valve seals do not always lead to leaks to the atmosphere or pose a loss of containment threat. Leaking valve seats can allow gas to flow when in the closed position. This poses a process safety threat, a loss of system performance (by creating recycle loops) and a less safe work environment (reducing the inability to complete maintenance activities that require double block and bleed). These valves are sometimes used to separate piping with different MOPs. If these valve seals leak, there is an increased threat of an overpressure event in lower-pressure pipe as gas bleeds through the valve from higher-pressure pipe.

Valve replacements are required at compressor stations for isolation valves which do not provide sufficient seal quality or are otherwise inoperative. These valves are typically remotely operable and are installed in various locations within the stations, providing key isolation during normal maintenance activities and/or emergency shutdown. Valves are identified for replacement based on operating performance or condition found during routine inspection. Replacement of associated actuators may be required and is evaluated on an individual basis.

The multi-year Header Valve Replacement Program will replace all mode valves on the compressor suction and discharge headers within the Corunna Compressor Station. The approach is to address two compressor units per year, with multiple valves being replaced per compressor unit. As required, new actuators will be purchased to match new valves and will be installed in conjunction with valve replacements.

5.3.5.4.5 MAINTENANCE- AND INSPECTION-DRIVEN REPLACEMENTS

Maintenance and inspection routines are used to determine the condition of assets and inform the need for intervention (timing and activity). Replacements are planned based on general asset groupings, failure characteristics and the ability to determine the time of failure. Where inspection techniques are feasible and can provide indication in advance of functional failure, replacements are planned based on condition. For assets where the distribution of failures is primarily random, (i.e., electronics, instrumentation) replacements are planned based on age. Assets that fail and can be replaced in a timeframe that does not jeopardize safety or reliability are candidates for a run-to-failure replacement strategy.

5.3.5.4.6 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, EGI intends to perform periodic condition assessments at critical facilities. 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.

5.3.5.4.7 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 prior to failure, based on historical obsolescence timeframes. 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)
- Instrumentation
- Electrical

5.3.5.4.8 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

5.3.5.4.9 SIEMENS VALVE CONTROLLER REPLACEMENT

As of July 2020, Siemens no longer supports 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. Similar to the fuel valve controllers, the oil scheduling valve and controller on the gas generator lube oil skid have been made obsolete. These valves and controllers have experienced several failures in recent years and cannot be rebuilt. The replacement program will replace valve controllers for two compressor plants per year through 2024.

5.3.5.4.10 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 5 to 8 years. This annual program is centrally managed to apply high-performance paint to mitigate corrosion at remote sites, four compressor facilities and one LNG facility with above-grade piping. This program targets stations with deteriorating coating condition, ensuring safety and reliability by reducing the probability of leaks and piping/equipment failure due to significant corrosion.

5.3.5.4.11 GHG EMISSION REDUCTIONS

EGI continues to evaluate and implement facility emission reduction opportunities. Effort is given to ensure the initiatives effectively balance customer preferences, compliance obligations, anticipated future regulations, and other noteworthy benefits such as safety and operational reliability.

When evaluating system expansion alternatives, the cost of fuel and carbon is considered alongside operational requirements, and these opportunities are tracked through the GHG Scope 1 & 2 Working Group. Significant investment has been made in the emission testing programs for both the Multi-Sector Air Pollutants Regulations (MSAPR) and federal methane regulations, in addition to the capital investments outlined in this plan.

For further detail on EGI's GHG emissions and targets, refer to Exhibit 1, Tab 10, Schedule 3. The asset class strategies contained in this asset plan are tied closely to EGI's efforts to reduce it environmental footprint. These efforts are summarized below.

Multi-Sector Air Pollutants Regulations (MSAPR)

The Multi-Sector Air Pollutants Regulations (MSAPR) are a compliance requirement and came into effect in 2017. These regulations are enacted by Environment and Climate Change Canada (ECCC) and are dedicated to limiting nitrogen oxide (NOx) emissions from specific industries and equipment across Canada. Part 2 of the regulation, focused on stationary-spark-ignition gaseous-fuel-fired engines greater than 250 kW (pre-existing), specifically impacts large stationary reciprocating engines at EGI. As of 2026, NOx emissions for all pre-existing, regular-use engines will need to meet 4 g/kWh. Modern engines greater than 75 kW (regular use), and greater than 100 kW (low use), manufactured after September 2016, are required to meet a limit of 2.7 g/kWh.

Direct Leak Inspection Program Requirements

The federal methane regulations are also a compliance requirement. The regulations came into effect on January 1, 2020 with the purpose of reducing methane emissions from the oil and gas industry through leak detection and repair (LDAR) requirements, venting limits and equipment level emission limits. As of January 1, 2020, the regulation requires facilities to implement an LDAR program and for compressor seals and rod packing to meet equipment emissions limits.

Leak inspections are required to be completed at compressor stations, storage measurement stations and transmission receipt / metering stations three times per year, with prescribed repair timelines. Leak repairs must be completed within 30 days or the next shutdown, with the shutdown scheduled prior to the point where the volume of gas saved by repairing the leak exceeds the volume of gas that must be vented from the pipeline in order to safely repair the leak.

Annual direct measurement or continuous monitoring of compressor-seal and rod-packing emissions is now required, with prescribed timelines for corrective action if the venting exceeds the applicable emission limits. Similar to LDAR repair timelines, corrective action must be completed within 90 days or the next shutdown, with the shutdown scheduled prior to the point where the total volume of leaked gas exceeds the volume of gas that must be vented in order to safely perform the corrective action.

As of January 1, 2023, the methane regulation will also require any continuous or high-bleed pneumatic device be replaced with a low- or no-bleed device. An application for an exemption from the limit may be made for individual pneumatic devices based on safety or operational needs.

Facility venting limits come into effect on January 1, 2023 and will apply to designated stations within the storage and transmission operations. All venting volumes will have a requirement to be calculated and tracked on a monthly basis, regardless of whether the venting activity is exempt from the venting limit. Vented activities exempt from the facility venting limit include blowdowns, glycol dehydration, pneumatics, start-ups/shutdowns and emergency venting.

5.3.5.4.12 STRATEGIC LAND PURCHASES

Properties in proximity to a compressor station have the potential to expose the general public to risks in the rare event of hazardous events. Noise and vibration are identified in the *Environmental Protection Act* as **contaminants**. Any industry emitting noise or other contaminants must obtain an Environmental Compliance Approval (ECA) from the Ontario Ministry of Environment, Conservation and Parks (MECP) in order to operate legally. The current approved ECA encompasses the entire gas storage and transmission network. If compressor stations with neighbouring lots are developed to host a noise-sensitive use, they could jeopardize the compliance status of the station with respect to the applicable MECP sound level limits. Acquiring land in proximity to compressor stations provides additional setback and buffer to ensure properties do not become noise-sensitive and reduce risk related to public safety and encroachment. Property may also be purchased to support expansion or provide ease of access.

5.3.5.4.13 DEHYDRATION ASSESSMENT

A risk assessment of the Dawn Hub send-out gas quality and a Reliability, Availability and Maintainability (RAM) study are underway to determine the risk associated with having a single dehydration system support the Dawn-Parkway system. Outcomes of the risk assessment and RAM study will be factored into future iterations of the AMP.

5.3.5.5 Compressor Stations Capital Expenditure Summary

The total average capital spend is forecast to be $56M (EGI) as summarized in **Table 5.3.5-3**. Storage and Transmission capital is further summarized as part of EGI's total 10-year capital plan in **Section 6**. See **Appendix B – IRP** for the status of the outcomes of the IRP assessment process, including the binary screen and the status evaluation of IRPAs.

Table 5.3.5-3: Compression Stations Asset Class Capital Summary ($ Millions) – EGI[24][25]

Asset Class Strategy/Investment Name	Asset Program	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-Year Forecast
Dawn C Compression Lifecycle	Replacements	0.2M	16.0M	32.2M	97.6M	17.3M	-	-	-	-	-	**163.4M**
Dawn to Corunna		158.7M	6.4M	-	-	-	-	-	-	-	-	**165.1M**
Dawn to Corunna (Dawn Tie-in)		47.9M	-	-	-	-	-	-	-	-	-	**47.9M**
Waubuno Compression Lifecycle		0.3M	1.6M	18.1M	0.1M	-	-	-	-	-	-	**20.1M**
Foundation Block Replacements	Replacements	3.4M	-	-	-	-	-	-	-	-	3.0M	**6.4M**
Facilities Integrity Management Program	Integrity	1.0M	0.2M	0.2M	0.1M	0.1M	0.1M	0.1M	0.1M	0.1M	0.1M	**1.9M**
Overhauls	Overhauls	1.0M	2.8M	9.9M	7.0M	4.8M	6.7M	0.4M	0.5M	1.0M	4.2M	**38.3M**
Valve Replacements	Replacements	1.5M	-	-	-	-	-	-	-	-	-	**1.5M**
Condition-based Replacements	Improvements	0.4M	-	-	-	-	-	-	-	-	-	**0.4M**
	Replacements	6.8M	1.2M	3.2M	4.1M	1.8M	1.5M	1.1M	1.1M	1.1M	1.1M	**22.9M**
Time-Based Replacement	Improvements	3.7M	0.9M	0.5M	0.7M	0.6M	0.6M	0.6M	0.6M	0.6M	0.6M	**9.4M**
	Replacements	1.2M	0.7M	2.1M	2.3M	1.3M	3.2M	1.5M	1.0M	2.0M	1.1M	**16.4M**
Run-to-Failure Based Programs	Improvements	6.9M	2.9M	1.4M	0.7M	0.3M	0.6M	1.5M	0.6M	0.4M	0.4M	**15.6M**
	Land/Structures	1.3M	0.5M	0.3M	0.9M	0.2M	0.4M	0.2M	0.3M	0.2M	0.2M	**4.7M**
	Replacements	0.4M	2.5M	0.5M	-	0.3M	-	-	-	-	-	**3.7M**
Siemens Valve Controller Replacement	Improvements	1.0M	0.4M	0.4M	-	-	-	-	-	-	-	**1.8M**
	Replacements	1.7M	1.0M	0.6M	0.1M	-	-	-	-	-	-	**3.4M**
High Performance Coating	Improvements	0.7M	0.7M	0.7M	0.7M	0.8M	0.8M	0.8M	0.8M	0.8M	0.8M	**7.5M**
GHG Emissions Reductions	Replacements	0.3M	0.9M	1.3M	1.3M	1.4M	1.4M	1.4M	1.4M	1.4M	1.4M	**12.1M**
Strategic Land Purchases	Land/Structures	-	-	-	-	3.5M	3.4M	3.4M	3.5M	3.5M	3.4M	**20.8M**
Total		**238.5M**	**38.6M**	**71.4M**	**115.6M**	**32.3M**	**18.7M**	**10.9M**	**9.9M**	**11.0M**	**16.2M**	**563.2M**

[24] Includes overhead allocation.
[25] Includes regulated capital only. Exhibit 1, Tab 13, Schedule 2 outlines EGI's Unregulated Storage Cost Allocations and Eliminations.

5.3.6 Transmission Pipe and Underground Storage

5.3.6.1 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 230 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 5.3-6** displays the ages of EGI well assets by drilling date (the original well construction date). **Figure 5.3-7** 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.

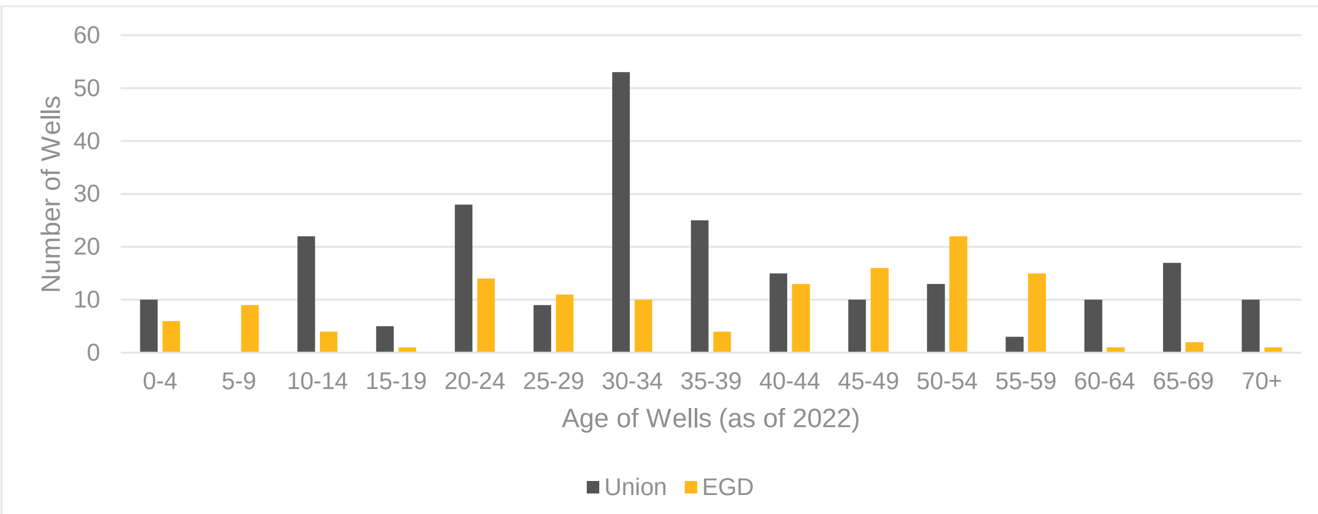


Figure 5.3-6: Age of Wells by Drilling Date

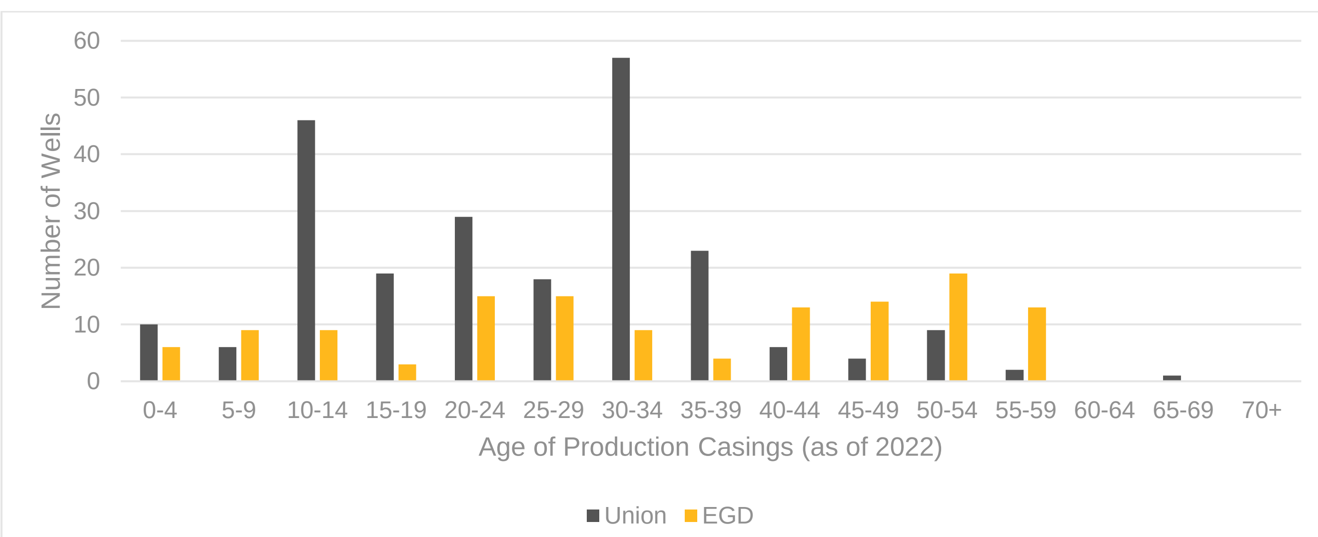


Figure 5.3-7: Age of Wells by Production Casing Age

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 m from the surface) can be repaired. These repairs, known as casing backoffs, 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 m 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.

5.3.6.1.1 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 5 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.

5.3.6.1.2 CONDITION FINDINGS

A condition model has been developed to predict the end-of-life for each storage well as shown in

Figure 5.3-8. 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.

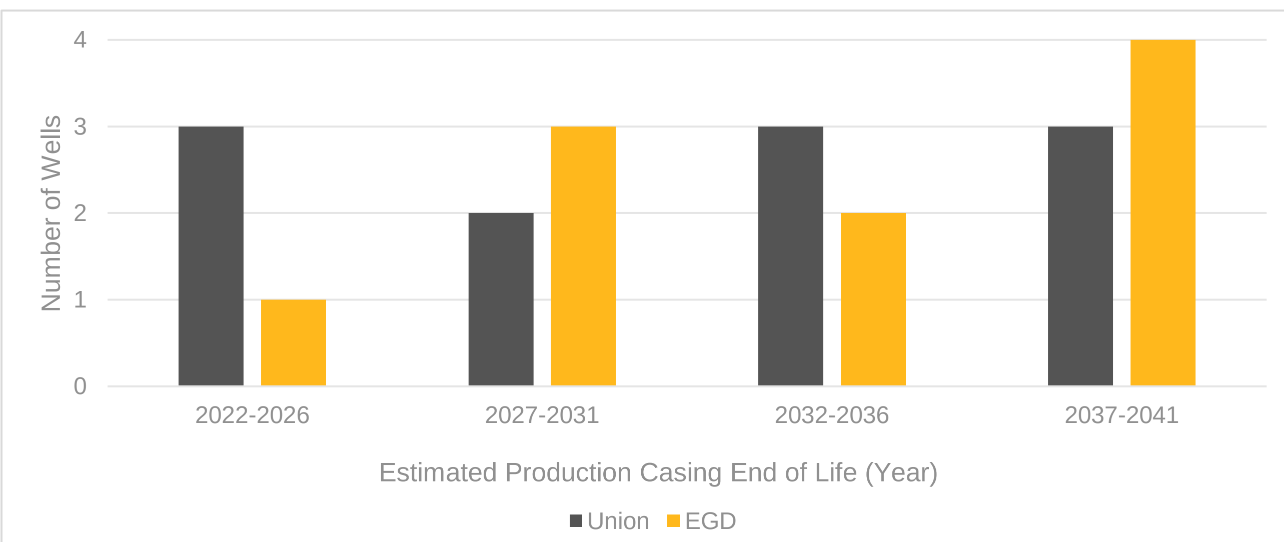


Figure 5.3-8: Estimated Production Casing End of Life for Wells

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 personnel 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 is installing four pre-cast concrete blocks around each fenced area 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. In 2021, EGI completed a study to determine if there were appreciable benefits of adding cathodic protection to those wells without. The study determined that implementing a cathodic protection (CP) solution, as used in Union wells, limits external corrosion (EC) and extends the service life of the well.

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. Additionally, evaluations have been completed on local market options with the aim of simplifying the operation of the pool. The outcome of these evaluations resulted in the recommendation to eliminate compression. An integrity assessment for each well has also been completed to determine if existing wells can be upgraded or will need to be abandoned. The findings of this assessment resulted in the requirement to replace eight observation wells and three storage wells as they do not meet standards and cannot be upgraded.

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.

5.3.6.1.3 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.

Employee and Contractor Health and Safety Risk / Public Health and 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.

Operational Risk: 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.

5.3.6.2 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.

Transmission System Reinforcement is described in the Growth Asset Class, refer to **Section 5.1.7.**

5.3.6.2.1 CONDITION METHODOLOGY

For the condition methodology of Pipe assets, see **Section 5.2.3.3.1**.

5.3.6.2.2 CONDITION FINDINGS

For the condition findings of Pipe assets, see **Section 5.2.3.3.2**. Specific findings for the following asset are also noted:

Panhandle Line Replacement

The two NPS12 river crossing pipelines cannot be inspected using in-line inspection (ILI), but their age and operating history infer 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.

A Threat Assessment Report prepared by a third-party consultant in November 2021 concluded that while most of the threats evaluated were classified as **low** severity, the threats of external and internal corrosion were classified as **moderate** and **considerable** respectively.

5.3.6.2.3 RISK AND OPPORTUNITY

For risks and opportunities of Pipe assets, see **Section 5.2.3.3.3**. Specific risks and opportunities for the following asset 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.

The threats considered have the potential to cause a complete outage of one pipeline along with a curtailment (due to pressure reduction) in the other, following a hypothetical hydrostatic test failure or the discovery of a large defect.

The Panhandle Transmission System relies on the river-crossing pipelines to meet firm customer needs on design day. The loss of both lines or restricted use of one line may impact the ability to serve firm customer demands subject to market conditions.

5.3.6.3 Transmission Pipe and Underground Storage Strategy Outcomes

The asset class strategies that apply to both the Transmission Pipe and Underground Storage and the Compression Stations asset classes are outlined in **Section 5.3.5.4**.

5.3.6.3.1 UNDERGROUND STORAGE

The capital maintenance and renewal programs for underground storage wells are as follows:

5.3.6.3.1.1 Well Casing Inspection, Maintenance and Replacements

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 2024 Rate Rebasing Customer Engagement Survey results where customers are supportive of investing to maintain current levels of safety and reliability.

5.3.6.3.1.2 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.

Crowland (PCRW) Wells Upgrade

The current scope of the Crowland Wells Upgrade project includes the abandonment and replacement of the eight observation wells. It also includes the abandonment of three storage wells to be replaced with two new wells. Upgrades to the remaining storage wells will include the installation of new wellheads and master valves. See **Appendix A, Pg. 51** for additional detail on this investment.

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.

5.3.6.3.1.3 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.

5.3.6.3.1.4 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.

5.3.6.3.1.5 Cathodic Protection

A benefit analysis study, completed in 2021, determined that implementing a cathodic protection (CP) solution, as used in Union wells, limits external corrosion (EC) and extends the service life of the well. Overall, the results show that due to the relatively low cost of CP compared to well replacement, there is a cost benefit to installing CP at any stage of the well's service life. Based on the report, the recommendation is to install CP on wells that do not currently have Cathodic Protection.

5.3.6.3.2 TRANSMISSION PIPE

For more details on the TIMP strategy for pipe assets including Inspection Program Integrity Retrofits and Digs, Depth of Cover Program and Class Location Program, see **Section 5.2.3.6.1**. For the Transmission System Reinforcement System Growth strategy outcomes, see **Section 5.1.9.4**. The following project is also noted:

Panhandle Line Replacement

EGI plans on replacing the two NPS 12 river crossing pipelines installed in 1947 with a single pipeline that can provide equivalent capacity. The new pipeline would be designed, manufactured and constructed to current standards and in-line inspection (ILI) capable. See **Appendix A, Pg. 55** for additional detail on this investment.

5.3.6.4 Transmission Pipe and Underground Storage Asset Class Capital Expenditure Summary

The total average capital spend is forecast to be $148M (EGI) as summarized in **Table 5.3.6-1**. Transmission Pipe and Underground Storage capital is further summarized as part of EGI's total 10-year capital plan in **Section 6**. See **Appendix B – IRP** for the status of the outcomes of the IRP assessment process, including the binary screen and the status evaluation of IRPAs.

Table 5.3.6-1: Transmission Pipe and Underground Storage Capital Summary ($ Millions) – EGI[26][27]

Asset Class Strategy/ Investment Name	Program Name	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-Year Forecast
Well Casing Inspection, Maintenance & Replacements	Improvements	1.1M	1.2M	2.3M	0.7M	2.4M	0.8M	2.4M	0.8M	2.5M	0.8M	**15.0M**
	Integrity	0.3M	0.3M	0.3M	0.3M	0.3M	0.3M	0.3M	0.3M	0.3M	0.3M	**2.8M**
	Land/Structures	0.1M	0.1M	0.1M	0.1M	0.1M	0.1M	0.1M	0.1M	0.1M	0.1M	**1.0M**
	Replacements	5.1M	12.9M	3.5M	3.0M	3.2M	3.2M	3.2M	3.3M	3.2M	3.1M	**43.7M**
Wellhead Upgrades	Improvements	1.3M	1.2M	0.4M	2.3M	0.4M	2.0M	0.4M	2.0M	0.4M	1.9M	**12.5M**
	Integrity	0.3M	0.3M	0.3M	0.4M	0.5M	0.4M	0.4M	0.5M	0.5M	0.4M	**3.9M**
Crowland (PCRW): Wells-Upgrade	Replacements	10.6M	2.2M	-	-	-	-	-	-	-	-	**12.8M**
Well Testing and Acid Stimulations	Improvements	0.3M	0.3M	0.3M	0.3M	0.3M	0.3M	0.3M	0.3M	0.3M	0.3M	**3.3M**
Well Accessibility	Land/Structures	0.1M	0.1M	0.1M	0.1M	0.1M	0.1M	0.1M	0.1M	0.1M	0.1M	**0.9M**
TIMP Retrofits and Digs	Integrity	23.1M	24.7M	23.1M	21.4M	23.9M	16.0M	15.9M	16.4M	17.9M	15.8M	**198.3M**
Depth of Cover Program		6.4M	3.3M	3.6M	4.8M	5.1M	5.1M	5.1M	5.2M	5.2M	5.0M	**48.8M**
Class Location Program	Class Location	2.7M	2.6M	4.0M	5.5M	7.3M	7.2M	7.2M	7.4M	7.3M	7.1M	**58.5M**
MOP Verification Program	Replacements	-	-	2.6M	5.2M	5.6M	5.5M	5.5M	5.7M	5.6M	5.4M	**41.0M**
Panhandle Line Replacement		2.0M	31.1M	4.4M	-	-	-	-	-	-	-	**37.5M**
Time-Based Replacement		0.5M	2.2M	0.0M	0.0M	0.0M	0.0M	0.0M	0.0M	0.0M	0.0M	**2.9M**

[26] Includes overhead allocation.
[27] Includes regulated capital only. Exhibit 1, Tab 13, Schedule 2 outlines EGI's Unregulated Storage Cost Allocations and Eliminations.

Asset Class Strategy/ Investment Name	Program Name	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-Year Forecast
Run-to-Failure Based Programs	Improvements	0.1M	0.1M	0.1M	-	-	-	-	-	-	-	**0.2M**
	Land/Structures	1.6M	0.3M	0.3M	0.3M	0.3M	-	-	-	-	-	**2.6M**
	Replacements	0.9M	0.7M	0.5M	0.5M	0.5M	0.5M	0.5M	0.5M	0.3M	0.3M	**5.0M**
Strategic Land Purchases	Land/Structures	-	-	-	-	2.8M	2.8M	2.7M	2.8M	2.8M	2.7M	**16.6M**
GHG Emissions Reductions	Improvements	0.6M	1.9M	0.1M	-	-	-	-	-	-	-	**2.6M**
Dawn Parkway Expansion Project (Dawn-Enniskillen NPS 48)	Growth[28]	-	-	-	-	34.2M	67.7M	202.5M	34.8M	-	-	**339.2M**
Dawn Parkway Expansion Project (Kirkwall-Hamilton NPS 48)	Growth[28]	-	24.4M	49.4M	149.9M	22.2M	-	-	-	-	-	**245.9M**
Panhandle Regional Expansion Project	Growth[28]	208.3M	11.0M	0.1M	-	-	-	-	-	-	-	**219.4M**
Panhandle Regional Expansion Project - Leamington Interconnect	Growth[28]	15.2M	50.8M	3.9M	-	-	-	-	-	-	-	**69.9M**
PREP: NPS 36 looping to Comber Transmission	Growth[28]	-	-	-	9.1M	19.4M	57.8M	9.6M	-	-	-	**95.9M**
Total		**280.7 M**	**171.7 M**	**99.3 M**	**204.0 M**	**128.6 M**	**169.9 M**	**256.2 M**	**80.3 M**	**46.5 M**	**43.4 M**	**1480.5 M**

[28] The Transmission System Reinforcement Strategy is outlined in **Section 5.1.9.4**.

5.3.7 Liquefied Natural Gas (LNG)

Hagar Station is EGI's liquefied natural gas (LNG) storage facility, located near Sudbury, Ontario (see **Figure 5.3-9**). 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 5.3-9: Hagar LNG Station Location

5.3.7.1 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.

Online monitoring provides protection via control systems and is supported by Control Room operators responsible for recognizing changing conditions and reacting in near real time. 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 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 related to an extended outage 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.

To support its primary function, the LNG facility includes mechanical systems such as 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 5.3-10**). The refrigeration system uses a mixed refrigerant consisting of methane, ethane, propane, butane and pentane. The condition of mechanical systems is assessed through routine PM inspections as prescribed by the manufacturer, through internally-developed standards or through opportunistic inspections presented during construction activities.

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 life cycle of equipment and systems and plan to proactively replace.

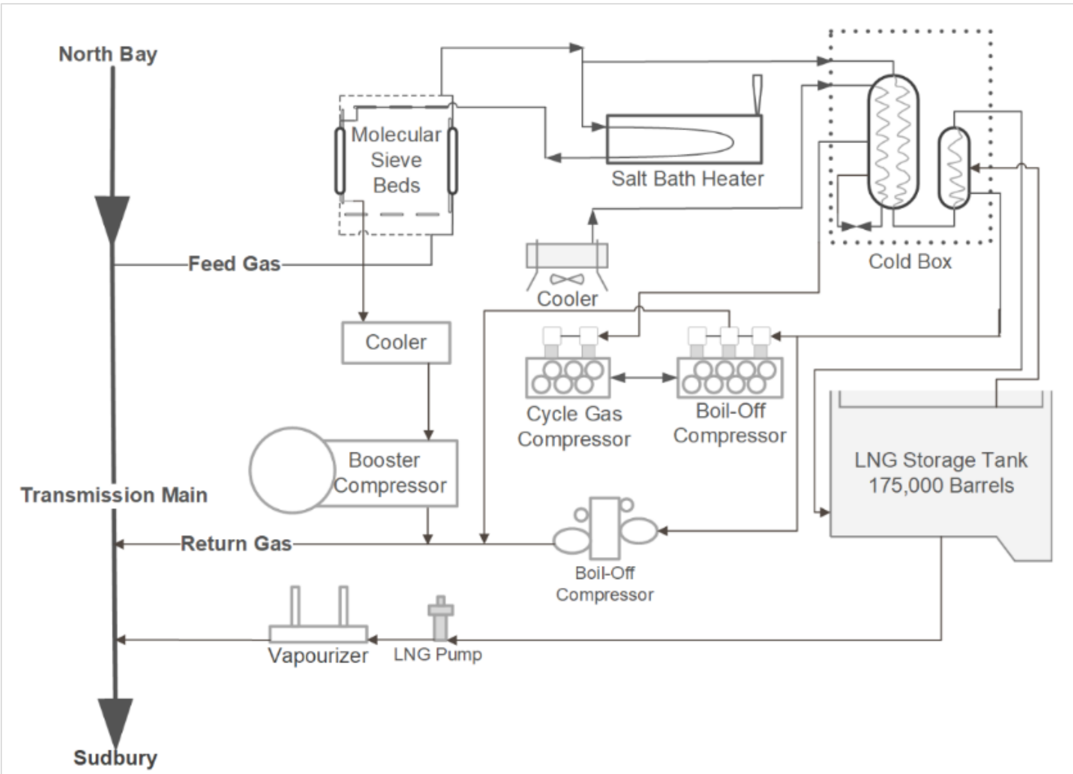


Figure 5.3-10: LNG Station

5.3.7.2 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 report 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. The BOG's original equipment has been in place since plant installation in 1968. A BOG compressor is a key LNG station component, and the typical lifespan is 20 years based on industry data and external SMA input. The report also indicated the cycle gas compressor has ~140,000 hours and the liquefaction system (composed of a cold box, cycle gas compressor, mixed refrigerant and auxiliary equipment) is considered to be 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. The condition assessment report also suggested insulation has been degrading; frequent stops and starts 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.

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 the engine or compressor block due to a crankshaft, connecting rod or piston rod failure. Replacement components would need to be cast, cured and machined.

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 could result in internal tank nozzle loading and potential cracking.

In addition to the condition report, to better understand risk associated with the facility, a Reliability, Availability and Maintainability (RAM) study was completed to inform operational risk and Quantitative Risk Assessment (QRA) to help understand Employee and Contractor Health and Safety Risk / Public Health and Safety Risk.

An analysis was conducted to understand the Operational Risk of Hagar LNG plant failing to supply vaporized LNG to Sudbury market which is its primary mission. The RAM study was conducted by external consultants and provided availability and likelihood of failure for the main systems in the plant that would result in Hagar's inability to supply vapourized LNG. Further, an internal Fault Tree Analysis (FTA) was conducted to determine the likelihood of Hagar being called to supply vapourized LNG due to weather conditions and demand. These analyses were used to determine the likelihood of the top event – Hagar unable to supply vapourized LNG to Sudbury market when called to do so. EGI performed network modelling to determine the consequence of the top event. The consequence is highly dependent on delivery pressure at Marten River Station from TC Energy Canadian Mainline. Therefore, two scenarios of contractual pressure of 580 psig and historical pressure of 800 psig were considered. The results are described in **Section 5.3.7.3**.

As a result of the QRA done at Corunna Compressor which revealed Risk Region 1 for worker safety event due to loss of containment, EGI assessed the Hagar facility as it shares a similar layout and characteristics as Corunna Compressor (i.e., multiple compressors in a single building). External consultants conducted a QRA at Hagar to analyze the H&S Individual Specific Individual Risk (ISIR) and Societal Risk (SR). The QRA is based on design and industry data for various different leak sizes and outcomes to evaluate process safety risk for public and worker and compares against targets. All risks identified were medium (Region 2).

5.3.7.3 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 supply 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 and availability 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. In the event that Hagar is required and cannot fulfil its function, the impact is significant (7 on EGI's 7x7 Operational Risk Matrix see **Figure 4.2-4**). Based on the expected shortfall results for the liquefaction, vapourization and compression modes from the RAM study combined with the historical weather demand, the likelihood of this event is low leading to an overall evaluation of the Operational Reliability Rik as a Medium.

Concerns related to obsolescence and the market availability of components for critical assets within the liquefaction process (BOG compressor, KVGR cycle gas compressor and cold box) can translate to customer impacts if the failure is unrepairable. An unrepairable failure is likely to result in extended downtime as other assets in the process may require replacement or modification for compatibility reasons.

Employee and Contractor Health and Safety Risk / Public Health and Safety Risk: The following conclusions can be drawn from the QRA of the Hagar LNG facility. As per EGI's risk evaluation criteria described in **Section 4.2.2**, it is found that none of the workers on the Hagar LNG site experience Individual Specific Individual Risk (ISIR) levels that fall within Region 1. However, all the worker groups have ISIR levels that fall in Region 2, where risk mitigation measures should be considered.

The ISIR levels for all off-site occupied areas fall within Region 3. No additional risk mitigation measures need to be considered for off-site ISIR, providing those existing protective measures are kept in place and the risk is monitored.

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.

GHG Emissions Reduction Opportunity: EGI continues to evaluate and implement facility emission reduction opportunities. Effort is given to ensure the initiatives effectively balance customer preferences, compliance obligations, anticipated future regulations, and safety and operational reliability.

5.3.7.4 LNG 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. As identified in the RAM study, on-going maintenance is critical to ensuring the sustained reliability and availability of the facility.

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. To inform the remaining life of assets, there is a need to gather more condition and performance information to continue to enhance understanding of risk and inform timing of intervention.

It would be difficult and impractical to replace any one major component in isolation due to compatibility issues with the existing plant. In the liquefaction process, the replacement of any major component (i.e., cold box or compressor) would require significant modifications to the new asset to make compatible with the existing equipment.

EGI will continue to re-evaluate new technology to support a holistic plan that considers the future demand and requirements for the distribution system, efficient production of LNG and environmental impacts.

The asset class strategies that apply to both the LNG and the Compression Stations asset classes are outlined in **Section 5.3.5.4**.

5.3.7.4.1 JVG BOIL-OFF GAS COMPRESSOR REPLACEMENT

This project involves replacement of the boil-off gas (BOG) compressor to mitigate the risk of a system failure due to a nonrepairable, 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 °C (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 is 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 and pistons 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 aftermarket 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. See **Appendix A, Pg. 30** for additional detail on this investment.

5.3.7.4.2 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 nonrepairable, critical compressor part. The KVGR compressor is one of 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 is deemed to be at the end of its design life. This replacement is required for the same reasons as the BOG compressor. See **Appendix A, Pg. 31** for additional detail on this investment.

5.3.7.4.3 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 could lead to customer outages. See **Appendix A, Pg. 29** for additional detail on this investment.

5.3.7.4.4 HAGAR LNG TANK BOIL-OFF GAS RECOVERY SYSTEM

During sudden atmospheric pressure changes, BOG venting from the LNG storage tank vents occurs frequently. The current BOG compressor is undersized for Hagar, which is one of GDS's largest emitters of unrecovered natural gas at approximately 590,000 m^3/yr. Boil-off gas is a single point source of emissions that can be recovered by installing a single process within the existing LNG facility. The solution proposed is to add a BOG compressor with its main function to compress the excess BOG and return it to the transmission line. The compressor would also be used as an alternate compressor to the Arial BOG compressor in the event of maintenance or breakdown. The scope of work for this project includes installation of a 450 HP compressor with electric motor drive (EMD), hydro service upgrade with generator backup, NPS 6 pipe from the tank relief valves, heat exchanger, flare system, miscellaneous cable trays, foundations, and piping.

5.3.7.5 LNG Asset Class Capital Expenditure Summary

The total average capital spend is forecast to be $8M as summarized in **Table 5.3.7-1**. Storage and Transmission capital is further summarized as part of EGI's total 10-year capital plan in **Section 6**. See **Appendix B – IRP** for the status of the outcomes of the IRP assessment process, including the binary screen and the status evaluation of IRPAs.

Table 5.3.7-1: Liquefied Natural Gas Capital Summary ($ Millions) – EGI[29]

Asset Class Strategy/Investment Name	Program Name	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-Year Forecast
JVG Boil-off Gas (BOG) Compressor Replacement	Replacements	-	-	-	-	-	-	-	-	2.1M	19.8M	**21.9M**
KVGR Cycle Gas Compressor Replacement		-	-	-	-	-	-	-	-	2.1M	23.9M	**26.0M**
Cold Box Replacement	Integrity	-	-	-	-	-	-	-	-	3.5M	11.5M	**15.0M**
Valve Replacements	Replacements	0.0M	-	-	-	-	-	-	-	-	-	**0.0M**
Time-Based Replacement		-	0.1M	-	-	0.3M	0.3M	0.3M	0.3M	0.3M	0.3M	**1.7M**
Run-to-Failure Based Programs	Improvements	0.2M	-	-	-	-	-	-	-	-	-	**0.2M**
	Land/Structures	0.0M	0.2M	0.5M	-	-	-	-	-	-	-	**0.8M**
	Replacements	-	0.1M	-	-	0.1M	0.1M	0.1M	0.1M	0.1M	0.1M	**0.9M**
GHG Emissions Reductions	Improvements	0.5M	-	-	1.2M	12.4M	-	-	-	-	-	**14.0M**
Total		**0.8 M**	**0.3 M**	**0.5 M**	**1.2 M**	**12.8 M**	**0.4 M**	**0.4 M**	**0.4 M**	**8.1 M**	**55.7 M**	**80.6 M**

[29] Includes overhead allocation.

5.4 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 office. The requirements for these properties are primarily based on function and headcount.

5.4.1 Real Estate and Workplace Services Objectives

The objectives of the Real Estate and Workplace Services asset class are listed in **Table 5.4.1-1**.

Table 5.4.1-1: REWS Asset Class Objectives

Asset Class Objective	Description
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 5.4.1-1**, asset investment decisions are governed by the life-cycle management strategies outlined in **Table 4.1-1.**

5.4.2 Real Estate and Workplace Services Hierarchy

The asset class hierarchy for Real Estate and Workplace Services is shown in **Figure 5.4-1.**

Figure 5.4-1: Real Estate and Workplace Services Hierarchy

5.4.3 Real Estate and Workplace Services Inventory

The inventory for Real Estate and Workplace Services assets is shown in **Table 5.4.3-1**.

Table 5.4.3-1: Real Estate and Workplace Services Asset Class Inventory[30]

Asset Subclass	EGI Rate Zone	Union Rate Zones
Properties (Buildings/Land)	18	74
Head Office	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.

[30] As of December 31, 2021.

5.4.4 Real Estate and Workplace Services Condition and Strategy Overview

Table 5.4.4-1: Real Estate and Workplace Services Condition and Strategy Overview

Asset Subclass/Program	Ownership	Condition	Risk / Opportunity	Maintenance Strategy	Replacement / Renewal Strategy
Properties (Buildings / Land)	Owned and leased	Facility assessments were conducted on EGI properties, based on a defined set of standards representing industry and EGI best practices relating to exterior site works, architectural elements, interiors, furniture and amenities. The assessments use both physical and functional criteria. The Functional Obsolescence or Adequacy Index (AI) is a condition index tool used to illustrate the functional condition of the asset. The Facility Condition Index (FCI), a generally-accepted industry benchmarking tool, is also used. All EGI properties were inspected for the purpose of calculating an FCI/AI in alignment with operational need to create a long-term capital plan. See **Table 5.4.5-1** for the condition findings for each property.	**Employee and Contractor Health and 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 Ontario Building Code [OBC] and energy standards). Inadequate site configuration and lack of office and support areas hinder operations and administrative functions. **Environmental Opportunity**: Older buildings have high greenhouse gas (GHG) emissions and use more energy than 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 support 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. Strategy options include • 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 in support of the business strategy.
Workplace Furnishings	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 Health and 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 and decreased access to light. **Financial Risk**: Legacy furnishings is past 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 for employees.
Building Systems Program	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. **Environmental Opportunity**: Older buildings have high GHG emissions and use more energy than a comparable new construction.	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	EGI completed a third-party study on energy efficiency and emissions for its office buildings. The study identified potential opportunities for improvement to reduce GHG emissions and improve energy efficiencies.	Existing facilities use more energy than a comparable new or renovated facility (using current OBC and energy standards). **Energy Efficiency Opportunity**: Reduction in operating costs and GHG emissions.	N/A	Existing building GHG reduction strategies at locations not planned for improvements or replacement in the 10-year plan will be addressed with a mix of measures. The range of implementation costs and energy/GHG savings will include operational and capital improvements.
Micro-Operations Depot Revitalization Program	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 1 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 Health and Safety Risk**: Current physical conditions pose a hazard to employee safety. **Environmental Opportunity**: 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 micro-operations depot sites that do not meet the functional requirements. 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.

5.4.5 Properties

5.4.5.1 Pandemic Impacts on EGI Real Estate

During the pandemic, EGI's utilization of its facilities has been broken down into continued essential operations and administration activities.

- The essential operations occupancies consisting of critical and field personnel that directly support EGI's operations have remained in the workplace throughout the pandemic, ensuring that the uninterrupted supply of gas is safely delivered to the millions of customers that depend on EGI every day.
- Administrative occupancies distributed throughout the operational footprint and mostly dedicated administration facilities such as VPC in Toronto and 50 Keil Drive in Chatham, had been working from home during the pandemic due to stay-at-home orders. As stay-at-home orders lifted, a cautious gradual return to a hybrid model consisting of majority of weekdays in-office, is in progress. EGI will continue to monitor and adhere to Chief Medical Officer of Health instructions and implement measures and recommendations from the ongoing pandemic.

5.4.5.2 Future Office Utilization

EGI values in-person collaboration and intends to leverage the learnings acquired during the COVID-19 pandemic to pursue options supporting workplace flexibility. Working differently during the pandemic provided insights about the positive aspects and challenges experienced by employees and the business without day-to-day interaction. These lessons will guide EGI to provide the best possible working experience for employees, while continuing to serve EGI's customers. EGI will evaluate options to leverage flexibility, while sustaining the importance of in person collaboration. EGI will monitor and measure utilization while also watching the marketplace for broadly adopted practices to inform EGI's future of workplace strategies. This will ensure a pragmatic and cost-effective transition of the real estate footprint.

5.4.5.3 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 shown below:

5.4.5.3.1 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. The FCI is calculated as follows:

5.4.5.3.2 FACILITY CONDITION INDEX CALCULATION

$$\mathbf{FCI} = \frac{\mathbf{Cost\ to\ Remediate\ Immediate\ or\ Short\text{–}\ term\ Maintenance\ Deficiencies}}{\mathbf{Current\ Replacement\ Value\ of\ Facility}}$$

Site functionality and utilization are based on critical functional criteria (yard size, access, sufficient office area and tracked utilization) 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 are 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/noncombustible 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.

5.4.5.4 Condition Findings

The facility assessment results for all EGI properties and the summary strategy for each property are shown in **Table 5.4.5-1**. Based on EGI's standards, FCI scores between 0% and 5% are considered good, 5% to 10% are fair, 10% to 30% are poor and greater than 30% are 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 and tracked utilization) and are scored as Good, Challenged, or Obsolete.

Table 5.4.5-1: EGI Facility Assessment Results

Property Name	Age (Years)	Physical Obsolescence (FCI)	Functional Obsolescence: Building (AI)	Functional Obsolescence: Site	Summary Strategy
50 Keil Drive	57	12.91%	45%	Obsolete	Renovation
555 Riverview Operations Centre	49	10.03%	24%	Good	Renovation
Lancaster Operations Centre	29	8.88%	63%	Obsolete	Expansion and Renovation
Arnprior Operations Centre	51	3.82%	58%	Obsolete	Renovation
Atikokan Micro-Operations Centre	54	11.37%	61%	Good	Revitalization Program
Barrie Operations Centre	16	1.61%	58%	Obsolete	Disposition
Black River Micro-Operations Centre	53	36.09%	46%	Good	Revitalization Program
Bloomfield Administration Centre	29	0.47%	0%	Good	Maintenance
Bracebridge Micro-Operations Centre	54	19.41%	32%	Good	Revitalization Program
Brampton Operations Centre	23	11.02%	49%	Obsolete	Renovation Interior/Exterior Alterations
Brantford Regional Operations Centre	26	2.77%	17%	Obsolete	Renovation
Brockville Operations Centre	51	7.53%	84%	Obsolete	New build and land
Burlington Operations Centre	13	1.77%	11%	Obsolete	Renovation
Cambridge Operations Centre	59	11.76%	16%	Obsolete	Disposition

Property Name	Age (Years)	Physical Obsolescence (FCI)	Functional Obsolescence: Building (AI)	Functional Obsolescence: Site	Summary Strategy
Cochrane Micro-Operations Centre	55	15.28%	50%	Good	Revitalization Program
Dawn Hub Operations Centre	51	16.95%	28%	Obsolete	New build on existing site
Dryden Operations Centre	42	11.33%	87%	Obsolete	New build on new site
Ear Falls Micro-Operations Centre	7	6.82%	56%	Good	Maintenance
Elliot Lake Micro-Operations Centre	42	29.09%	13%	Good	Revitalization Program
Engelhart Micro-Operations Centre	Unknown	25.42%	83%	Good	Revitalization Program
Geraldton Micro-Operations Centre	57	12.09%	68%	Good	Revitalization Program
Guelph Operations Centre	64	14.97%	46%	Obsolete	Disposition
Haileybury Micro-Operations Centre	56	22.60%	18%	Good	Revitalization Program
Hamilton Operations Centre (Park Street)	61	26.86%	100%	Obsolete	Disposition
Hamilton Operations Centre (Pritchard Road)	14	7.91%	21%	Obsolete	Renovation
Hearst Micro-Operations Centre	48	6.76%	79%	Good	Revitalization Program
Huntsville Micro-Operations Centre	52	24.34%	52%	Good	Revitalization Program
Huron Park Micro-Operations Centre	81	42.40%	22%	Good	Disposition
Iroquois Falls Micro-Operations Centre	55	28.84%	16%	Good	Revitalization Program
Kapuskasing Micro-Operations Centre	31	7.156%	61%	Good	Maintenance
Kelfield Operations Centre	61	10.47%	71%	Obsolete	New build and land
Kennedy Road Operations Centre	61	6.51%	95%	Obsolete	New build and land
Kingston Operations Centre	12	0.32%	15%	Good	Maintenance

Property Name	Age (Years)	Physical Obsolescence (FCI)	Functional Obsolescence: Building (AI)	Functional Obsolescence: Site	Summary Strategy
Kirkland Lake Micro-Operations Centre	57	11.38%	69%	Good	Revitalization Program
Leamington Operations Centre	60	9.85%	65%	Good	Renovation
London Operations Centre	53	6.48%	14%	Good	Disposition
Milton Operations Centre	27	14.09%	63%	Obsolete	Disposition
Nipigon Micro-Operations Centre	58	10.27%	57%	Good	Revitalization Program
North Bay Operations Centre	57	16.87%	8%	Good	New build on new site
Orillia Operations Centre	47	18.07%	15%	Obsolete	Disposition
Oshawa Operations Centre	32	14.92%	30%	Obsolete	Renovation
Ottawa Regional Operations and Admin. Centre	60	4.65%	43%	Obsolete	Consolidation
Owen Sound Operations Centre	15	4.52%	32%	Obsolete	Expansion and Renovation
Palmerston Micro-Operations Centre	Unknown	9.56%	89%	Good	Revitalization Program
Parry Sound Micro-Operations Centre	8	3.75%	19%	Good	Maintenance
Peterborough Operations Centre	40	10.38%	32%	Obsolete	Disposition
Sault Ste. Marie Operations Centre	43	13.90%	24%	Good	Renovation
Simcoe Operations Centre	65	8.42%	100%	Good	Demolish and New Build
SMOC (operations centre)	26	2.04%	24%	Obsolete	Disposition
St. Thomas Operations Centre	42	12.59%	22%	Obsolete	Disposition
Station B Operations Centre	53	12.28%	49%	Obsolete	New build
Stratford Operations Centre	54	11.96%	22%	Good	Expand on current land Disposition

Property Name	Age (Years)	Physical Obsolescence (FCI)	Functional Obsolescence: Building (AI)	Functional Obsolescence: Site	Summary Strategy
Sudbury Operations Centre	37	8.49%	13%	Obsolete	Renovation
Tecumseh (Engineering)	12	0.28%	0%	Good	Maintenance
Tecumseh (Gas Storage)	5	0.81%	0%	Good	Maintenance
Thorold Regional Operations and Admin. Centre	29	3.09%	59%	Obsolete	Renovation
Thunder Bay Regional Operations Centre	25	2.57%	41%	Obsolete	Renovation
Timmins Operations Centre	62	2.88%	25%	Good	Renovation
TOC Regional Operations and Admin. Centre	10	0.08%	5%	Good	MEC and Telemetry Expansion
VPC Head Office	53	5.59%	11%	Good	Renovation, new build
Woodstock Operations Centre	39	13.87%	26%	Obsolete	Renovation

5.4.5.5 Risk and Opportunity

Examples of deficiencies observed at EGI sites were as follows:

- Inadequate building or yard size leads to unfulfilled operational requirements.
- Buildings do not conform to current OBC life safety, barrier-free and universal design standards.
- Site area constraints hinder vehicular circulation and increase the probability of motor vehicle incidents.
- Configuration of site functions and circulation is inefficient.

These deficiencies pose the following risks:

Employee and Contractor Health and Safety Risk: Facilities with operational deficiencies pose a health and 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. Inadequate site configuration and lack of office and support areas hinder operations and administrative functions.

Environmental Opportunity: Some facilities use more energy than a comparable renovated facility (utilizing current OBC and applicable municipal energy standards). Older buildings have high GHG emissions and use more energy than comparable new construction.

5.4.6 Workplace Furnishings

5.4.6.1 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 (30-plus 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 past 30 years of 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 inches 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.

5.4.6.2 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), Technology and Operations Centre (TOC) properties and 50 Keil Drive, all other EGI's workplace furnishings are rated as legacy based on EGI standards.

5.4.6.3 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 reconfiguration 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.

The risks and opportunities are described in **Table 5.4.4-1**.

5.4.7 Real Estate and Workplace Services Strategy Outcomes

5.4.7.1 Property Upgrade Strategy

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 5.4.5.3** and support of the business strategy.

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 EGI facilities. Major projects include the following:

Kelfield Operations Centre

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 61 years. The office and operational areas no longer meet the needs of the business.

The strategy for Kelfield Operations Centre is to sell the existing property, purchase a new property (approximately 5 acres) and build a new facility on the new site. This strategy will ensure adequate yard space for operational activities. A new building also corrects the identified deficiencies, eliminating the identified risks.

Kelfield is primarily an operations facility with an administrative component; and as such, future office occupancy strategies will have limited impact on use and design. Learnings about future ways of working will be incorporated for the administrative portion of the design. See **Appendix A, Pg. 32** for additional detail on this investment.

Kennedy Road Expansion

The facility does not meet functional and physical requirements. The existing building at the Kennedy Road facility is too small to meet requirements. The separation of offices and warehouse into two separate buildings 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. The office and operational areas no longer meet the needs of the business.

The strategy for the Kennedy Road facility is to purchase the adjacent property (approximately 2 acres), demolish the existing buildings on site, and build a new facility on the combined site. This strategy will leverage current site improvements and keep land acquisition cost to a minimum by joining the currently vacant neighbouring property. Kennedy Road is primarily an operations and warehousing facility with an administrative component; and as such, future office occupancy strategies will have limited impact on use and design. Learnings about future ways of working will be incorporated for the administrative portion of the design. See **Appendix A, Pg. 34** for additional detail on this investment.

SMOC/Coventry Facility Consolidation

The office building in Ottawa is an owned facility that is in fair physical condition. The functional requirement is marginal and the large facility is underutilized. The two facilities overlap in coverage area. The current site area at either facility cannot satisfy the combined yard and parking requirement. The office and operational areas no longer meet the needs of the business.

The strategy is to sell both existing properties and purchase a property suitable in size to accommodate the combined program of South Merivale Operations Centre (SMOC) and Coventry Road. The required size of the new property is approximately 7-plus acres. This option ensures that the site footprint is adequate for current activities, building deficiencies are corrected, and combines the SMOC and Coventry locations to correct the service coverage duplication currently existing between the two facilities and is in close proximity to major highways to ensure optimal operational travel time. The Ottawa facilities are primarily operations facilities with an administrative component; and as such, future office occupancy strategies will have limited impact on use and design. Learnings about future ways of working will be incorporated for the administrative portion of the design. See **Appendix A, Pg. 36** for additional detail on this investment.

VPC Core and Shell

The building shell and core for the Victoria Park Centre (VPC) facility is over 50 years old. The tower building was constructed in 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. The building envelope is deemed safe but can no longer maintain a reliable wind and rain screen and is nearing end of life. EGI will maintain and have periodic third-party inspections of structural integrity.

The strategy is to correct physical and functional deficiencies by replacing the envelope and renovating and renewing the existing core building systems on the existing site. This is the preferred strategy as the FCI and AI indices show the building and site deficiencies are correctable on the existing property. See **Appendix A, Pg. 41** for additional detail on this investment.

Station B New Building

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 and functional condition does not meet requirements and the office and operational areas no longer meet the needs of the business.

The strategy is to demolish the existing facility and build a new building while maintaining the area of the existing yard. This will ensure adequate yard space for operational activities. A new building also corrects the identified deficiencies, eliminating the identified risks. EGI requires a downtown site in support of operational activities. Alternate site availability is unavailable due to required outside storage and industrial use. A proposed neighbouring development reduces EGI's opportunities for expansion. On the current site, EGI's uses are grandfathered with enough yard area to accommodate requirements and continued use. The site's proximity to the future Ontario line multi-modal station will help reduce GHGs by encouraging staff to utilize public transit. Station B is primarily an operations facility with an administrative component; and as such, future office occupancy strategies will have limited impact on use and design. Learnings about future ways of working will be incorporated for the administrative portion of the design. See **Appendix A, Pg. 38** for additional detail on this investment.

New London Site

The London depot on 109 Commissioners Rd. W. is an owned property in a good location but does not meet current building standards or operational requirements. The physical and functional condition does not meet requirements. This project will allow for consolidation of operational sites in the Union rate zones into a single facility.

The Huron Park depot on 420 Quebec Ave. is an owned property in a good location but does not meet current building standards or operational requirements. The physical and functional condition does not meet requirements. This project will allow for consolidation of operational sites in the Union rate zones into a single facility.

The St. Thomas depot on 25 Sparling Rd. is an owned property in a good location but does not meet current building standards or operational requirements. The physical and functional condition does not meet requirements. This project will allow for consolidation of operational sites in the Union rate zones into a single facility.

The Simcoe depot on 54 Hillcrest Rd. is an owned property in a good location but does not meet current building standards or operational requirements. The physical and functional condition does not meet requirements. This project will allow for consolidation of operational sites in the Union rate zones into a single facility. The office and operational areas no longer meet the needs of the business.

The Huron Park, Simcoe, St. Thomas and London sites overlap in coverage area.

The strategy for the new London site is to correct physical and functional deficiencies by purchasing a new site and build a single, combined facility on the new site which will correct operational coverage overlap and is in close proximity to major highways to ensure optimal operational travel time. London is primarily an operations facility with critical functions, warehousing, and an administrative component; and as such, future office occupancy strategies will have limited impact on use and design. Learnings about future ways of working will be incorporated for the administrative portion of the design. See **Appendix A, Pg. 43** for additional detail on this investment.

North Bay Regional Operations Centre

The North Bay depot on Charles Street is an owned property in an inappropriate residential location and does not meet current building standards and operational requirements. The physical and functional condition does not meet requirements. The office and operational areas no longer meet the needs of the business.

The strategy is to purchase a new property in North Bay (approximately 10 acres) and build a new facility on the new site. North Bay is primarily an operations depot; and as such, future office occupancy strategies will have limited impact on use and design.

Dawn Hub

The Dawn Hub on Bentpath Line is an owned property that does not meet current building standards or operational requirements. The physical and functional condition does not meet requirements. The office space no longer sufficiently accommodates current and future needs of the business.

The strategy is to construct a new facility elsewhere on the Dawn campus. This presents the safest, most cost-effective solution. Dawn Hub is primarily an operations facility with critical functions and a small administrative component; and as such, future office occupancy strategies will have limited impact on use and design. See **Appendix A, Pg. 45** for additional detail on this investment.

5.4.7.2 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. 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.

5.4.7.3 GHG and Energy Reductions Program

EGI 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 10-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/GHG 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 10 years, based on building assessments and condition analysis.

5.4.7.4 Micro-Operations Depot Revitalization Program

This program covers the renovation or replacement of micro-operations depots located in the Northern region that are on average over 50 years old. 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 health and 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 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.

5.4.7.5 Workplace Furnishings Replacement Program

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.

5.4.8 Real Estate and Workplace Services Capital Expenditure Summary

The total average capital spend is forecast to be $52M (EGI) as summarized in **Table 5.4.8-1**. REWS capital is further summarized as part of EGI's total 10-year capital plan in **Section 6**.

Table 5.4.8-1: REWS Capital Summary ($ Millions) – EGI[31]

Asset Class Strategy/Investment Name	Asset Program	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-Year Forecast
Property Upgrade Strategy	Furniture/Structures & Improvements	5.6M	1.3M	8.3M	9.4M	22.3M	15.9M	13.0M	15.5M	11.7M	2.4M	105.5M
Kennedy Road Expansion		0.3M	25.3M	23.3M	-	-	-	-	-	-	-	48.9M
SMOC/Coventry Facility Consolidation		13.7M	6.4M	-	-	-	-	-	-	-	-	20.1M
Station B New Building		24.9M	11.5M	-	-	-	-	-	-	-	-	36.5M
VPC Core and Shell		-	-	-	-	-	-	-	14.1M	13.9M	8.1M	36.2M
New London Site		-	1.9M	23.9M	26.1M	-	-	-	-	-	-	51.9M
Kelfield Operations Centre - Land Purchase		-	-	-	32.7M	-	-	-	-	-	-	32.7M
Kelfield Operations Centre - New Building		-	-	-	-	16.7M	13.8M	-	-	-	-	30.5M
Thorold Regional Office - Building & Site		0.3M	0.3M	6.5M	10.5M	4.2M	0.0M	-	-	-	-	21.7M
Dawn Administrative Centre		-	-	-	-	1.4M	16.5M	-	-	-	-	17.9M
Sudbury Regional Operations Centre		-	-	2.1M	13.0M	-	-	-	-	-	-	15.1M

[31] Includes overhead allocation.

Asset Class Strategy/Investment Name	Asset Program	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-Year Forecast
Building Systems Program		5.6M	5.8M	7.5M	7.7M	8.3M	8.5M	8.5M	9.0M	8.9M	8.8M	78.6M
GHG and Energy Reductions Program		0.9M	0.9M	0.9M	0.9M	1.0M	1.0M	1.0M	1.0M	1.0M	0.9M	9.4M
Micro-Operations Depot Revitalization Program		0.3M	2.6M	2.6M	2.6M	0.0M	0.0M	0.0M	0.0M	0.0M	0.0M	8.1M
Workplace Furnishings Replacement Program		0.5M	0.5M	0.7M	0.7M	0.7M	0.7M	0.7M	0.8M	0.9M	0.8M	7.0M
Total		**52.1 M**	**56.6 M**	**75.6 M**	**103.5 M**	**54.6 M**	**56.4 M**	**23.3 M**	**40.4 M**	**36.4 M**	**21.0 M**	**519.9 M**

5.5 Fleet and Equipment

The Fleet and Equipment asset class provides EGI with the necessary vehicles, equipment and tools to run regulated business operations safely and efficiently. 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 lb. to 150,000 lb. Heavy equipment assets consist 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.

The Fleet and Equipment asset class supports the organization's energy transition priority through the diversification of EGI's fleet fuels. Built into EGI's strategy is the continued pursuit of natural gas, electric and renewable fueled vehicles as they become available in the market.

5.5.1 Fleet and Equipment Objectives

Table 5.5.1-1 describes the asset class objectives for Fleet and Equipment.

Table 5.5.1-1: Fleet and Equipment Asset Class Objectives

Asset Class Objectives	Description
Supportability	Provide the business with the necessary vehicles, equipment and tools to run regulated business operations safely and efficiently, based on fit-for-purpose analysis.
Integrity and Reliability	Sustain the safety and reliability of all vehicles, equipment and tools.
	Combine risk, life-cycle costs and performance information to drive asset-related decisions.
Energy Transition	Support the organization's energy transition by sourcing vehicles with lower carbon fuels.

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 5.5.1-1**, 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 other fuel sources, including but not limited to natural gas and electric, reducing overall greenhouse gas (GHG) emissions.
- Optimize natural gas and electric as fuel sources for LDVs to reduce overall GHG emissions.
- Install Auxiliary Power Units (APUs) on MDVs. An APU is an anti-idling device that reduces overall GHG emissions and prevents premature engine wear and tear.
- Install telematics/GPS technology to optimize asset utilization.
- Use telematics/GPS technology to create a proactive approach to vehicle maintenance and reduce downtime.

5.5.2 Fleet and Equipment Hierarchy

The asset subclass breakdown for the Fleet and Equipment asset class is illustrated in **Figure 5.5-1**.

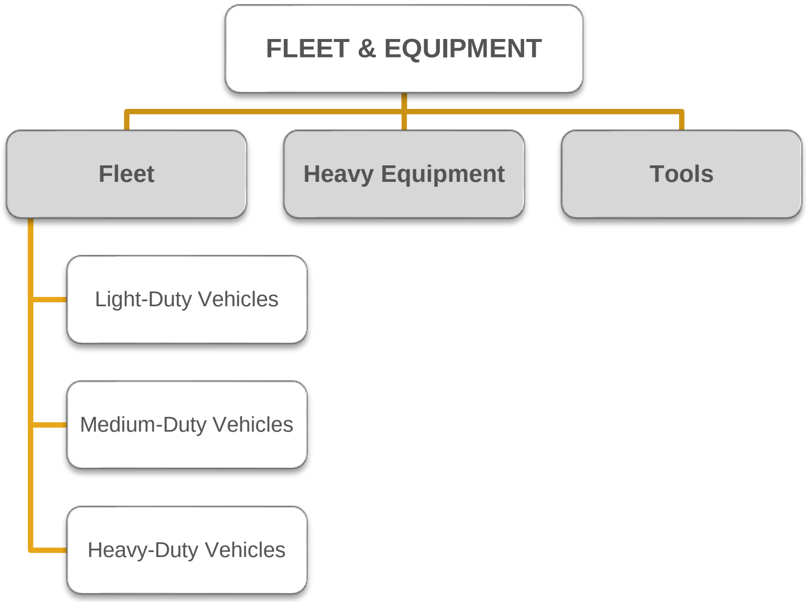


Figure 5.5-1: Fleet and Equipment Asset Class Hierarchy

5.5.3 Fleet and Equipment Inventory

The Fleet and Equipment asset class inventory is shown in **Table 5.5.3-1**.

Table 5.5.3-1: Fleet and Equipment Inventory[32]

Asset Subclass	EGD Rate Zone	Union Rate Zones
Fleet	1,069	826
Light-Duty Vehicles	880	550
Medium-Duty Vehicles	6	233
Heavy-Duty Vehicles	183	43
Heavy Equipment	689	510
Tools	~5,000	~6,000

[32] As of November 15, 2021.

5.5.4 Fleet and Equipment Condition and Strategy Overview

Table 5.5.4-1: Fleet and Equipment Condition and Strategy Overview

Asset Subclass		Max Age (Year)	Current Condition	Risk / Opportunity	Maintenance Strategy	Replacement / Renewal Strategy
Fleet	**Light-Duty Vehicles**	10.6 (EGD RZ) 9.0 (Union RZ)	Analysis indicates that average maintenance costs exceed the market value of a light-duty vehicle at approximately 72 months old or 145,000 km, 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 km (approximately every 6 months)	**Light-Duty Vehicle (LDV) Replacement Strategy**: This proactive program replaces vehicles based on weight class, mileage and assessed condition. The average replacement age for LDVs is 72 months.
	Medium-Duty Vehicles	18.6 (EGD RZ) 10.4 (Union RZ)	Analysis indicates that average maintenance costs exceed the market value of a medium-duty vehicle at approximately 144 months old or 175,000 km, depending on the vehicle’s weight class.		Vehicle maintenance every 10,000 km or 500 engine hours (approximately every 6 months)	**Medium-Duty Vehicle (MDV) Replacement Strategy**: This proactive program replaces vehicles based on weight class, mileage and assessed condition. The average replacement age for MDVs is 144 months.
	Heavy-Duty Vehicles	15.2 (EGD RZ) 16.2 (Union RZ)	Analysis indicates that average maintenance costs exceed the market value of a heavy-duty vehicle at 144 months old or 350,000 km, depending on the vehicle’s weight class.		Vehicle maintenance every 10,000 km or 500 engine hours (approximately every 6 months)	**Heavy-Duty Vehicle (HDV) Replacement Strategy**: This proactive program replaces vehicles based on weight class, mileage and assessed condition. The average replacement age for HDVs is 144 months.
Heavy Equipment		21.4 (EGD RZ) 15.8 (Union RZ)	Analysis indicates that average maintenance costs exceed the market value of heavy equipment at approximately 144 months old.		Equipment maintenance is conducted on a scheduled basis, ranging from 3 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 Health and Safety Risk / 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

5.5.5 Fleet

5.5.5.1 Condition Methodology

EGI continues to harmonize and optimize its Fleet and Equipment processes and procedures. In 2020, fleet data was migrated to an enterprise-wide fleet management service provider to leverage fleet management software (i.e., Element). This system stores asset records and analyzes vehicle condition over its life cycle, including 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.

Retaining vehicles and heavy equipment for periods longer than optimal, 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 (i.e., Geotab). The Geotab system also provides real-time vehicle diagnostics, giving EGI the ability to be proactive with fleet vehicle assessments and repairs.

5.5.5.2 Condition Findings

Figure 5.5-2 shows the average age for fleet assets across EGI.

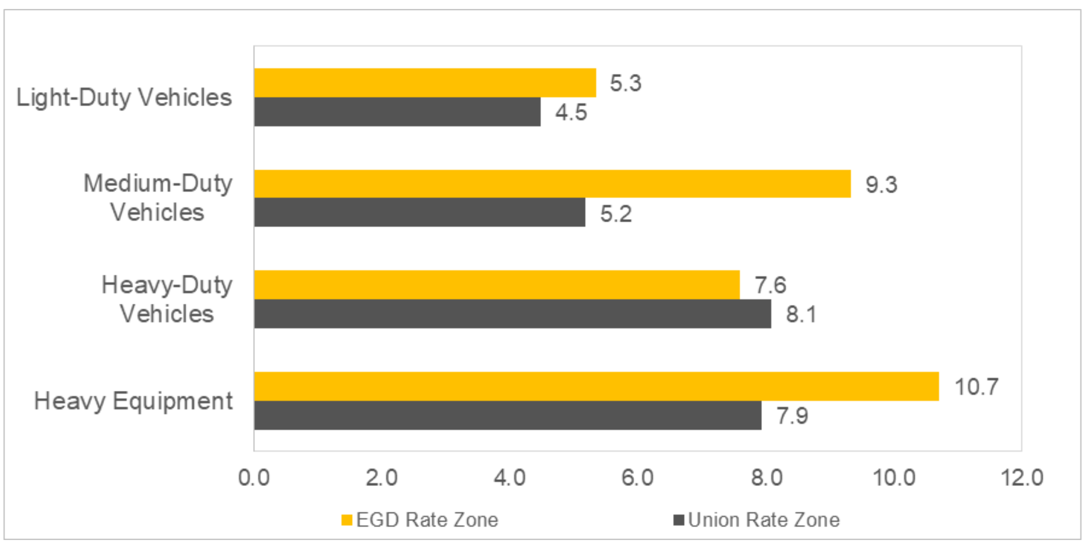


Figure 5.5-2: EGI Current Average Vehicle Age (Years)

As **Figure 5.5-2** shows, the current average age of fleet assets for the rate zones are higher than what would be ideal based on the condition methodology described above. This highlights the need for increased investments to ensure that fleet replacements continue to occur as per the replacement strategy.

5.5.5.3 Risk and Opportunity

Fleet vehicles and heavy equipment assets (see **Section 5.5.6**) 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 and can affect EGI's ability to serve its customers.
- Decreased resale value

Based on the value assessment analysis, fleet vehicles primarily pose a financial risk to EGI if they are not maintained or replaced as needed. Maintenance costs increase after the vehicle warranty expires 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 EGI's customers, potentially creating a risk to customer satisfaction.

5.5.6 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.

5.5.6.1 Condition Methodology

The analysis of heavy equipment assets used the same condition methodology for fleet vehicles (see **Section 5.5.5.1**).

5.5.6.2 Condition Findings

The average age for heavy equipment is 128 months for the EGD rate zone and 95 months for the Union rate zones. Analysis indicates that average maintenance costs exceed the market value of heavy equipment at approximately 144 months old (see **Figure 5.5-2**).

Based on Fleet Management system reporting, industry standards and asset assessment trends, the typical average useful life threshold for heavy equipment is at approximately 144 months 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 shown in **Figure 5.5-2**, the average age of heavy equipment assets for EGD and Union rate zones are 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.

5.5.6.3 Risk and Opportunity

Fleet vehicles and heavy equipment assets have similar risks and opportunities (see **Section 5.5.5.3**).

5.5.7 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 and grease guns. 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.

5.5.7.1 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.

5.5.8 Fleet and Equipment Strategy Outcomes

5.5.8.1 Vehicle Replacement Strategy

EGI's strategy is to source and purchase all vehicle and equipment assets to support business operations and objectives, including the conversion to other fuel sources allowing EGI to continue to reduce overall GHG emissions.

As part of integration activities, a comparison of EGD and Union rate zones' 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 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. The replacement cycles for the various vehicle classes are shown in **Table 5.5.8-1**.

Table 5.5.8-1: Vehicle Replacement Cycle

Class	Replacement Cycle (months)	Replacement Cycle (km)
Light-Duty	72	145,000
Medium-Duty	144	175,000
Heavy-Duty	144	350,000

5.5.8.2 Heavy Equipment Replacement Program

EGI's replacement strategy 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).

5.5.8.3 Tools Replacement Program

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.

5.5.9 Fleet and Equipment Capital Expenditure Summary

The total average capital spend is forecast to be $46M (EGI) as summarized in **Table 5.5.9-1**. Fleet and Equipment capital is further summarized as part of EGI's total 10-year capital plan in **Section 6**.

Table 5.5.9-1: Fleet and Equipment Capital Summary ($ Millions) – EGI[33]

Asset Class Strategy	Program Name	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-Year Forecast
Heavy Equipment Replacement Program	Equipment & Materials	8.6 M	9.8 M	10.8 M	11.9 M	15.6 M	15.9 M	16.0 M	16.8 M	17.2 M	15.0 M	**137.7 M**
Tools Replacement Program	Tools	3.2 M	3.4 M	3.5 M	3.6 M	3.9 M	3.9 M	4.0 M	4.2 M	4.2 M	4.2 M	**38.2 M**
Vehicle Replacement Strategy	Vehicles	13.7 M	21.9 M	22.1 M	25.0 M	34.0 M	32.4 M	32.6 M	34.2 M	35.0 M	30.5 M	**281.4 M**
Total		**25.5 M**	**35.0 M**	**36.4 M**	**40.5 M**	**53.6 M**	**52.3 M**	**52.6 M**	**55.2 M**	**56.5 M**	**49.7 M**	**457.2 M**

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33 Includes overhead allocation.

5.6 Technology and Information Services

The Technology and Information Services (TIS) asset class includes the Infrastructure, Software and Communications subclasses. TIS continues to support process and system integration while in parallel reducing EGI operational and cybersecurity risks. EGI continues to align systems, processes and procedures, prioritized based on business value (customer experience, efficiency, safety/reliability, and compliance) while adopting industry best practices regarding cloud computing where feasible.

The infrastructure asset subclass has three types of assets: (1) laptops/desktops, (2) desktop sustainment equipment and (3) network and 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.

Network and security infrastructure hardware assets include network components, security appliances and telephony equipment. Network hardware consists of routers, switches, hubs, firewalls, devices required to maintain voice communication and video-conferencing networks. 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 infrastructure 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 infrastructure 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 overarching objective is to ensure that TIS applications and related technologies provide desired functionality, adapt with evolving customer expectations, 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.

5.6.1 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 5.6.1-1**.

Table 5.6.1-1: 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 protect the asset against threats and vulnerabilities.
Availability	Ensure that infrastructure, devices and/or applications/software are readily available for use when required and will work as intended.

Asset Class Objectives	Description
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 infrastructure incidents
- Number of change and enhancement requests
- Incident response time and resolution time met

To achieve the TIS asset class objectives listed in **Table 5.6.1-1**, asset investment decisions are governed by the life-cycle management strategies outlined in **Table 4.1-1**.

5.6.2 Technology and Information Services Hierarchy

The asset subclass hierarchy for the TIS asset class is shown in **Figure 5.6-1**.

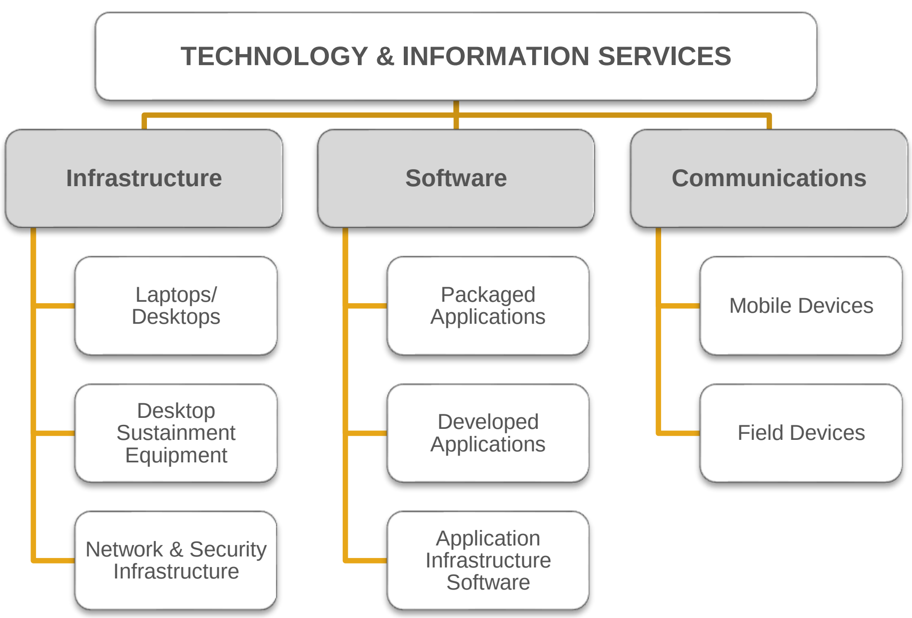


Figure 5.6-1: Technology and Information Services Hierarchy

5.6.3 Technology and Information Services Inventory

The TIS asset class inventory is shown in **Table 5.6.3-1**.

Table 5.6.3-1: TIS Asset Class Inventory[34]

Asset	EGD Rate Zone	Union Rate Zones	Integrated
Infrastructure			
Laptops and Desktops	1,958	2,207	-
Desktop Sustainment Equipment	N/A*	N/A*	-
Network and Security Infrastructure	2,240	3,201	-
Software			
Packaged Applications	125	113	6
Developed Applications	44	47	3
Application Infrastructure Software	25	22	-
External Service	11	5	-
Communications			
Mobile Phones	4,310	1,505	-
Field Devices	1,281	607	-

Note: Desktop Sustainment Equipment assets are not recorded in inventory.

[34] As of December 13, 2021.

5.6.4 Technology and Information Services Condition and Strategy Overview

Table 5.6.4-1: 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. **Cyber & Security Risk**: Aging assets can go unsupported with no patches available by vendors resulting in higher likelihood of successful cyberattack.	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 Health and 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. **Cyber & Security Risk**: Aging assets can go unsupported with no patches available by vendors resulting in higher likelihood of successful cyberattack.	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.
Network and Security Infrastructure	3	Network 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 infrastructure incidents and outages and an increase in maintenance costs.	Servers and appliances are replaced proactively based on age, compliance and warranty status.	**Network Infrastructure and Security Renewal Strategy**: EGI's strategy is to replace network 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 • Infrastructure to meet vendor support requirements • Software to meet vendor support life cycle (for packaged applications) • Ability to enhance and support existing applications For the condition findings for this subclass, see **Table 5.6.6-1** and **Table 5.6.6-2**.	**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 infrastructure repairs **Operational Risk**: Extended application and system outages, inadequate (or the lack of) applications required for employees to complete assigned tasks, contributing to difficulties in meeting customer needs **Reputational Risk**: Cybersecurity exposure due to the inability to apply required security patches potentially leading to negative reputational impacts for EGI if any breaches occur. **Cyber & Security Risk**: Aging assets can go unsupported with no patches available by vendors resulting in higher likelihood of successful cyberattack.	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 For the condition findings for this subclass, see **Table 5.6.6-3**.		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 forecast changes to existing software products and business requirements.
Mobile Devices	2	The condition of mobile devices is not proactively monitored.	**Employee and Contractor Health and Safety Risk / Public Health and Safety Risk**: Inadequate (or the lack of) mobile devices hinder	Mobile devices are maintained internally to address performance issues.	**Mobile Device Renewal Strategy**: EGI follows industry best practices for replacing

Asset Subclass	Avg. Age (Year)	Condition	Risk / Opportunity	Maintenance Strategy	Replacement / Renewal Strategy
			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.	Damaged devices are repaired/replaced on an as-needed basis within the three-year replacement window.	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 Health and Safety Risk / Public Health and Safety Risk**: Inadequate (or the lack of) field devices hinder 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; impacting response to customer needs. **Cyber & Security Risk**: Aging assets can go unsupported with no patches available by vendors resulting in higher likelihood of successful cyberattack.	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.

5.6.5 Infrastructure

5.6.5.1 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.

5.6.5.1.1 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.

5.6.5.1.2 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.

5.6.5.1.3 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 infrastructure become obsolete, resulting in an asset that is more expensive to repair.
- Existing infrastructure 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.

5.6.5.2 Desktop Sustainment Equipment

Desktop sustainment assets include all TIS infrastructure equipment required for business operations. Audio/visual equipment, printers, monitors, keyboards, mice, privacy screens and headsets are some examples of desktop sustainment equipment.

5.6.5.2.1 CONDITION METHODOLOGY

The condition of desktop sustainment equipment is evaluated on the following:

- New hire onboarding information
- Infrastructure incident requests
- Feedback and requests from ergonomic specialists and business users

The condition and health of desktop sustainment equipment is not proactively monitored.

5.6.5.2.2 CONDITION FINDINGS

Annually, there are approximately:

- 4,055 ergonomic-related requests requiring ergonomic equipment
- 1,455 onboarding requests requiring desktop sustainment equipment to support new employees/contractors
- 2,995 infrastructure incidents

5.6.5.2.3 RISK AND OPPORTUNITY

The major risks identified for desktop sustainment equipment are captured in **Table 5.6.4-1**.

5.6.5.3 Network Infrastructure and Security

5.6.5.3.1 CONDITION METHODOLOGY

Network 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 network 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.

5.6.5.3.2 CONDITION FINDINGS

Core and security infrastructure asset failures can occur for a variety of reasons, including hard drive failures, processor failures, memory failures and significantly degraded performance.

5.6.5.3.3 RISK AND OPPORTUNITY

The major risk identified for network and security infrastructure 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 infrastructure is not compatible with newer operating systems and applications, resulting in an asset with reduced functionality.
- Maintenance costs can become excessive after warranty expiry.

5.6.6 Software

5.6.6.1 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.

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.

As software license assets reach end of life, EGI is adopting a cloud-based model, as described in **Section 5.6.8.1**.

5.6.6.1.1 CONDITION METHODOLOGY

The condition of packaged and developed applications is evaluated on the following:

- Ability to meet business requirements
- Infrastructure to meet vendor support requirements
- Software to meet vendor support life cycle (for packaged applications)
- Ability to enhance and support existing applications

5.6.6.1.2 CONDITION FINDINGS

Table 5.6.6-1 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 5.6.6-1: Application State – Key Packaged Applications[35]

Application	Application Overview	Age (Years)	Application State
AutoSol Communication Manager (UG)	Polling engine application for reading measurement information	16	Hardware is currently under warranty. Software is current and supported.
Corrosion Survey Management System (CSMS)	Application for leak survey inspection-related work	5	The solution is built on eGIS, the application software will be upgraded in 2022.
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	8	Software update completed in 2018.
Customer Information System (CIS)	Customer care and billing applications (SAP, CIS and Banner)	1	CIS applications used in EGD and Union rate zones migrated to an SAP cloud-based solution in 2021 as part of EGI integration. Future upgrades are planned in 2023 and 2028.
EGI Extranet	EGI external website for the EGD rate zone with self-service capabilities	4	Hardware was replaced in 2017/2018. Rewrite and foundational software upgrade occurred in 2017/2018. This application was integrated with the uniongas.com extranet in 2021.
Geographic Information System (ESRI eGIS)	Application for developing geographic views of EGD rate zone asset data	8	Hardware was replaced in 2020. Software was upgraded in 2020.
GIS Suite - G/Technology (Hexagon)	Application for developing geographic views of Union rate zone asset data	7	Application was upgraded in 2020 to maintain supportability.
GMAS	Collection and validation system for measurement information in the Union rate zones	21	Hardware is currently under warranty. Software is current and supported.

[35] *Copperleaf is not listed as it is managed by Corporate Services.*

Application	Application Overview	Age (Years)	Application State
ITRONFCS	Used to facilitate the meter reading process in EGD and Union rate zones	2	Software was upgraded in 2019. Consolidation of services completed to single platform in 2021.
Leak Survey Management System (LSMS)	Application for leak survey inspection-related work	6	The solution is built on eGIS, which was upgraded in 2020. The application software will be upgraded in 2022.
PIMSlider	Application for analyzing asset condition data and the optimal lifespan of assets	5	Hardware is currently under warranty. Software is current and supported.
Powerspring (formerly Metretek)	Application providing automated meter readings for large volume customers in the EGD rate zone	4	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	5	Application upgraded in 2020 to maintain support.
PureConnect	Call centre application for call management in EGD and Union rate zones	2	Software and hardware upgraded in 2021.
SCADA	Supervisory control and data acquisition systems that monitor and control underground transmission pipelines	2	Hardware was upgraded in 2019 as part of the GDS control centre migration and SCADA consolidation. Software upgraded in 2020.
Teldig	Locate-tracking application used through Ontario One Call	8	Hardware was upgraded in 2019. Application software was upgraded in 2019.
Work and Asset Management (WAMS)	Application to manage work and assets	5	Functional changes and technical upgrades planned for 2023.

Table 5.6.6-2 summarizes the key developed applications used at EGI and outlines their current state and condition.

Table 5.6.6-2: 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	11	Hardware is currently under warranty. Software was upgraded in 2018.
Classify Allocation Report and Exchange (CARE and CARE.Net)	Nominations and scheduling system for gas storage, transportation and capacity planning. Includes direct purchase and unbundled in the Union rate zone	26	Application is aging, replacement is needed in order to ensure business continuity, mitigate risk of service outages, degraded performance and cyber security risks.
Construction Administration Records System (CARS)	Application managing construction work orders for new customer service lateral attachments	21	This application is to be replaced by the Asset Work Management System in 2022.

Application	Application Overview	Age (Years)	Application State
Contrax	Application used to create, renew, manage and bill non-cycle large volume customers. Includes direct purchase and storage & transmission in the Union rate zone	3	Hardware is currently under warranty. Software is current and supported.
Cross Bore Risk Mitigation	Analytics tool used to assess the probability of cross bores	3	Hardware is currently under warranty. Software is current and supported.
Customer Connections Worksuite	Application for managing Customer Connections information	5	This application is to be replaced by the Asset Work Management System in 2022.
eApp	Tool used to submit natural gas services requests online	11	This application is being integrated with the GetConnected application used in the Union rate zones in 2022 as part of EGI integration.
Energy Cost Reporting (EnCore)	Application used to develop cost models for energy supply	7	Hardware is currently under warranty. Software is current and supported.
EnTrac	Management software for large volume and direct purchase contracts in the EGD rate zone	17	Hardware was out of warranty in 2021 and moving to Cloud platform. Software is current and supported.
Field Record Access (FRA)	Application used to locate asset information	2	Application is aging, replacement is needed in order to ensure business continuity, mitigate risk of service outages, degraded performance and cyber security risks.
Finance Business Analysis (FBA)	Data warehouse for reconciliation of customer consumption	6	Hardware is currently under warranty. Software is current and supported.
GetConnected	Tool used to submit natural gas services requests online	11	This application is being integrated with the eApp application used in the EGD rate zone in 2022 as part of EGI integration.
iViewer	Image repository for as as-laid drawings, scans of service tickets and field notes	11	Hardware is currently under warranty. Application software upgraded in 2020 to maintain support.
Land Management (rowAMPS)	Application to manage land/property and municipal taxation work	4	Cloud solution as a service offering; implemented in 2017.
Revenue Analysis and Volume Estimation (RAVE)	Application for volumetric analysis, estimation and budgeting	17	Hardware is currently under warranty. Software is current and supported.

Application	Application Overview	Age (Years)	Application State
Unbundled Rate Compliance (URICA)	Application to request and track unbundled services as per Natural Gas Electricity Interface Review (NGEIR) direction in the EGD rate zone	14	Application is aging, replacement is needed in order to ensure business continuity, mitigate risk of service outages, degraded performance and cyber security risks.
Enerline (Formerly Unionline)	Secure web-based tool providing online services to contract customers	21	Application is aging, replacement is needed in order to ensure business continuity, mitigate risk of service outages, degraded performance and cyber security risks.

5.6.6.1.3 RISK AND OPPORTUNITY

The major risks identified for packaged and developed applications captured in **Table 5.6.4-1**.

5.6.6.2 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.

5.6.6.2.1 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

5.6.6.2.2 CONDITION FINDINGS

The current age and state of key application infrastructure software used at EGI is shown in **Table 5.6.6-3**.

Table 5.6.6-3: 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	19	2	Software is current and supported.
Harvest	Source code management software	21	9	Software is supported.
Quality Assurance and Testing Suite	Testing and quality assurance tool suite	18	1	Software is supported.
Microsoft SQL Server	Database management software	21	1	Software is current and supported.
Oracle Database	Database management software	22	1	Upgraded to current version in 2021.

Application	Application Overview	Age (Years)	Year(s) since last refresh	Application State
Oracle Fusion	Integration suite providing interfacing capabilities between applications	8	1	Software is current and supported.
Oracle Golden Gate	Data replication software	6	1	Software is current and supported.
Oracle WebLogix Application Server	Management software for deployment and execution of applications	18	4	Software is current and supported.
SAP Business Objects Reporting Suite	Suite of reporting tools for business reporting and analytics	13	1	Upgraded to current version in 2021.
Team Foundation Server	Foundational software used for .Net application development	16	9	Software is supported.

5.6.6.2.3 RISK AND OPPORTUNITY

The risks identified for application infrastructure software are the same as for packaged and developed applications (see **Table 5.6.4-1**).

5.6.7 Communications

5.6.7.1 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.

5.6.7.1.1 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 to log a ticket through ServiceNow. In addition, the TIS asset class relies on new hire and business needs requests for equipping new mobile device users.

5.6.7.1.2 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.

5.6.7.1.3 RISK AND OPPORTUNITY

The major risks identified for mobile device assets are:

- **Employee and Contractor Health and 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.
- **Financial Risk**: Inability of employees to be productive through inaccessibility of mobile devices
- **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 and lead to loss of supply or extended outages for customers.

5.6.7.2 Field Devices

Field devices include ruggedized laptops, Toughpads and Toughbooks, printers, plotters and multi-function devices, GPS devices and truck modems for signal strengthening.

5.6.7.2.1 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

5.6.7.2.2 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.

5.6.7.2.3 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 hinder the ability of employees to respond to emergency field situations due to device unavailability.
- **Financial Risk**: Lack of availability of field devices impacts productivity for employees
- **Operational Risk**: Inadequate (or the lack of) field devices may result in productivity loss due to increased time travelling between office and job sites, missed appointment windows, and extended service outages.

5.6.8 Technology and Information Services Strategy Outcomes

5.6.8.1 Cloud Computing Services Adoption

EGI has adopted cloud computing services to reduce outages from infrastructure failures, reduce cyber-attack exposure, leverage a scalable core infrastructure, reduce technical debt and improve business reliability, as assets reaching end of life create material operational risk for hosted systems. In addition, on-premise license models are no longer available within the software industry.

Historically, EGI purchased its software licenses and IT infrastructure systems and would capitalize the costs and amortize them over time. In cloud computing, a cloud services user does not own the underlying assets, as the cloud subscription is expensed under the Operations and Maintenance (O&M) budget. The transition to cloud computing services results in higher O&M costs as spending shifts away from capital.

5.6.8.1.1 TYPES OF CLOUD SERVICES

EGI uses three types of cloud services:

Software as a Service (SaaS)

- SaaS refers to software applications that are delivered over the Internet, on demand and usually via subscription.
- Cloud providers host and manage the software and associated infrastructure and handle maintenance (i.e., upgrades).
- Users connect to applications over the Internet (via web browser on smart devices or via personal computers (PCs).
- Using this cloud delivery model, IT productivity costs, such as Microsoft Office 365, are charged back as O&M via Cost Allocation Methodology (CAM) and are no longer regarded as an Asset Management Plan (AMP) capital expenditure.

Platform as a Service (PaaS)

- PaaS refers to cloud computing services that provide an on-demand environment that developers use to develop, test, deliver and manage software applications.
- PaaS allows developers to create web or mobile apps without the need to set up or manage the underlying infrastructure (i.e., servers, storage, networks and databases).
- SAP Canada is the external service provider administering the Customer Information System (CIS) application using this cloud delivery model.

Infrastructure as a Service (IaaS)

- EGI pays for scalable IT infrastructure from a cloud provider on a pay-as-you-go basis. Infrastructure components include servers, storage and operating systems.
- IaaS can be at a fixed or scalable capacity.
- Using this cloud delivery model, core infrastructure, server and storage costs are charged back as O&M via CAM and are no longer regarded as capital expenditure.

5.6.8.2 Infrastructure Strategy Outcomes

5.6.8.2.1 LAPTOPS AND DESKTOP RENEWAL STRATEGY

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.

5.6.8.2.2 DESKTOP SUSTAINMENT EQUIPMENT STRATEGY

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.

5.6.8.2.3 CORE INFRASTRUCTURE AND SECURITY RENEWAL STRATEGY

EGI's strategy is to replace servers and appliances for core infrastructure and security infrastructure 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 infrastructure 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 infrastructure 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 vendors.

5.6.8.3 Software Strategy Outcomes

5.6.8.3.1 PACKAGED AND DEVELOPED APPLICATIONS RENEWAL STRATEGY

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 forecast 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. As applications are developed or replaced, an increasingly important aspect of this work is the development of appropriate measures to address cyber security risk. EGI integration will drive a number of application replacements and migrations during the 2023 to 2032 timeline.

The following packaged and developed applications have been identified for the next 10 years:

- **Records Management**: This technology obsolescence investment aligns records management processes, data, asset structure, systems of record and drafting practices for gas carrying asset records which is used to support Operations in performing maintenance and construction work and Engineering to conduct analysis. See **Appendix A, Pg. 49** for additional detail on this investment.
- **Contract Market Harmonization and Contract Market Systems – Technology Obsolescence**: This obsolescence investment addresses technology that is or will become unsupported soon and requires upgrading to reduce technology complexity and cyber risk, and to enable integration, rate and service harmonization, and further enhance the customer experience. The harmonization investment is envisioned to deliver system enablement of processes and reliability for contract markets to ensure consistent, reliable operations from contract to cash (payment) including a consistent, technology-enabled customer experience. This project is also required to implement the harmonized services proposed for this market, detailed in Exhibit 8, Schedule 4, Tab 1. See **Appendix A, Pg. 45 & 46** for additional detail on these investments.
- **General Service Rebasing Changes:** This project will harmonize the existing EGI rate zones and customer classes into a single rate zone with common customer classes. EGI will assess the rate harmonization while considering the Ontario Energy Board's (OEB's) Mergers, Amalgamations, Acquisitions and Divestitures (MAADs) requirement to file a proposal for rate harmonization as part of the rebasing application. This project is also required to implement the general service rate design, detailed in Exhibit 8, Schedule 2, Tab 3. See **Appendix A, Pg. 48** for additional detail on this investment.
- **SCADA**: This initiative is to modernize and standardize EGI SCADA solution.

5.6.8.3.2 APPLICATION INFRASTRUCTURE RENEWAL STRATEGY

A proactive replacement strategy is in place for application infrastructure software, driven by forecast changes of existing software applications business requirements.

The maintenance strategy is reactive; performance issues or software defects are addressed as they are identified.

5.6.8.4 Communications Strategy Outcomes

5.6.8.4.1 MOBILE DEVICE RENEWAL STRATEGY

The TIS asset class strategy for mobile devices is to stay one release cycle behind manufacturer releases as mobile devices are available at a 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.

5.6.8.4.2 FIELD DEVICES RENEWAL STRATEGY

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.

5.6.9 Technology and Information Services Capital Expenditure Summary

The total average capital spend is forecast to be $63M (EGI), as summarized in **Table 5.6.9-1.** The TIS capital is further summarized as part of EGI's total 10-year capital plan in **Section 6**.

Table 5.6.9-1: TIS Capital Summary ($ Millions) – EGI[36]

Asset Class Strategy/Investment Name	Program Name	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-Year Forecast
Laptop/Desktop Renewal Strategy	TIS Infrastructure	1.7M	6.7M	4.3M	4.5M	4.9M	8.3M	5.0M	5.2M	5.3M	8.5M	**54.4M**
Desktop Sustainment Equipment Strategy		1.0M	1.1M	1.1M	1.2M	1.3M	1.3M	1.3M	1.4M	1.4M	1.4M	**12.6M**
Core Infrastructure and Security Renewal Strategy		4.5M	3.3M	3.1M	3.9M	3.6M	3.4M	3.2M	4.2M	4.1M	3.7M	**37.0M**
Developed and Packaged Applications Renewal Strategy	TIS Business Solutions	40.2M	38.9M	35.1M	32.5M	30.9M	34.0M	31.9M	30.4M	30.6M	27.2M	**331.7M**
Application Infrastructure Renewal Strategy		1.6M	2.6M	1.0M	1.2M	1.3M	1.1M	1.3M	1.5M	1.0M	1.2M	**13.7M**
Contract Market Harmonization		2.5M	6.4M	6.5M	3.6M	-	-	-	-	-	-	**19.0M**
Contract Market Systems - Technology Obsolescence		9.3M	22.8M	23.0M	13.2M	-	-	-	-	-	-	**68.4M**

[36] Includes overhead allocation.

Asset Class Strategy/Investment Name	Program Name	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-Year Forecast
General Service Rebasing Changes		-	17.9M	2.6M	-	-	-	-	-	-	-	**20.5M**
Records Management Upgrade		-	5.4M	11.2M	11.3M	-	-	-	-	-	-	**27.9M**
Mobile Device Renewal Strategy	TIS Infrastructure	0.4M	0.4M	0.5M	0.6M	0.6M	0.6M	0.6M	0.7M	0.7M	0.7M	**5.7M**
Field Device Renewal Strategy	TIS Business Solutions	2.5M	-	-	4.9M	-	-	-	-	2.8M	-	**10.2M**
	TIS Infrastructure	-	6.8M	0.3M	-	5.6M	5.3M	2.1M	-	-	11.3M	**31.3M**
Total		**63.7 M**	**112.4 M**	**88.7 M**	**76.9 M**	**48.1 M**	**54.1 M**	**45.3 M**	**43.4 M**	**45.9 M**	**53.9 M**	**632.6 M**

6 Summary of Capital Expenditure

6.1 Portfolio Optimization

Using the methodology for optimization outlined in **Section 4.3.3**, 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 and management process (risk, opportunity, customer engagement feedback, and resource constraints), this plan provides critical direction for the baseline facility need over the next 10 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/opportunity, cost and performance.
- Execution risks were reasonable (resource capacity).
- Initiatives identified as mandatory were justified, based on:
  - Exceeding an established risk threshold
  - Third-party relocation
  - Program work with sufficient history and risk to warrant continuation
  - Projects that meet the economic feasibility tests in EBO 188 and EBO 134
  - Compliance requirements
  - Investments that were already executing with costs continuing into 2023 to 2032 and the remaining work could not be shifted.

In total, 1,500 EGD rate zone (RZ) investments and 1,901 Union RZ investments were included in the initial pre-optimized request for capital. The initial pre-optimized request is illustrated in **Figure 6.1-1** and **Figure 6.1-2**, generated from the asset investment planning tool (Copperleaf).

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 asset needs and financial considerations. Determining the capital constraint involves EGI's Asset Management, Finance and Regulatory departments. To complete EGI's latest portfolio optimization, EGI considered optimization constraints for 2023 and for the remainder of the 10-year plan separately.

For 2023, the assets for the EGD RZ and Union North and South RZs, were maintained separately for capital planning purposes as 2023 is the final year of the approved five-year (2019 to 2023) deferred rebasing term from the MAADS Decision (*EB-2017-0306/EB-2017-0307*). For the 2024 to 2032 optimization constraint, EGI considered historical spend levels, inflation, smoothing the impact to ratepayers and the capital to meet asset class strategy needs.

EGI's optimization constraints were determined through the following efforts:

- For 2023, EGI recognized that two significant projects are expected to go into service in that year - Dawn to Corunna Project (see **Appendix A, Pg. 1**) and the Panhandle Regional Expansion Project (see **Appendix A, Pg. 55**). EGI first attempted to leverage the materiality threshold as the constraint for 2023 but was unable to accommodate the significant volume of compliance, must-do, and in-flight work. In the end, the 2023 Budget was constrained to $1.5B, the amount that had previously been included in the long-range plan created in 2022.

- To set a constraint for the remainder of the 10-year plan, EGI looked at scenarios between the 2023 Materiality Threshold of ~1.4B and the historical average spend of ~$1.17B[37]. In each case an escalation of 2% for inflation was applied (see **Table 6.4-1** for inflation assumptions). Through the process of moving the optimization constraint line downwards from $1.4B to $1.1B, EGI examined:
    - Implications to asset class strategies
    - Implications to in-service capital (as a proxy for impact to ratepayers)
    - Implications for the management of identified risk
    - Ability to complete mandatory work
    - Ability to complete work that supports the energy transition
    - Ability to complete work that is in keeping with customers' stated preferences
    - Organizational capacity to complete work

  Through consultation with a wide range of internal stakeholders, EGI determined that the 2024-2032 optimization constraint of $1.2B with an annual escalation of 2% for inflation allowed for safe and reliable outcomes through execution of EGI's asset class strategies. EGI had to treat specific significant investments (Dawn C Compression Lifecycle in 2026 [see **Appendix A, Pg. 3**] and Dawn-Parkway Expansion [Dawn-Enniskillen NPS 48 in 2029 [see **Appendix A, Pg, 53**]) as exceptions to the optimization constraint in order to obtain the optimized result in those years.

  The increase in capital for 2024 relative to the historical average is attributed to the following:
    - +$129M in market driven growth with several large growth investments identified with spend in 2024 including: Panhandle Regional Expansion Project (PREP), PREP: Leamington Interconnect, Wheatley 1B PREP Reinforcement, East Kingston Creekford Road Reinforcement and the Dawn Parkway Expansion Project (Kirkwall-Hamilton NPS 48). The timing for these investments is based on the market requirements, EGI will evaluate the market driven investments for technically and economically feasible IRPAs.
    - +$107M in planned replacements have shifted into 2024 to provide additional time for EGI to assess and adequately demonstrate the condition of the pipelines as an outcome of the St. Laurent LTC Decision.
    - +$95M in compliance related investments including increases to meter and regulator exchanges due to increased costs for meters and large numbers of meters reaching expected end of seal life. In addition, updated hazard assessments completed under EGI's Transmission Integrity Management Program have identified the need to review and mitigate high and moderate uncertainties in the fitness-for-service conclusions of the review.

  Optimization constraints lower than $1.2B (i.e., $1.1B) caused the optimization to fail as they do not accommodate all investments with fixed timing. Examples of investments with fixed timing that must be executed in a given year include:
    - Compliance work must be completed in accordance with rules and regulations, deferring this work could result in EGI being out of compliance.
    - Relocations must be completed in a given year order to ensure that the work triggering the relocation is completed. Relocation projects are subject to the timing of the work triggering the relocation and as such timing of these projects is fixed.
    - Reinforcements have fixed timing because absent the reinforcement, EGI would not be able to attach customers to its system after the reinforcement is required.
    - Executing work has fixed timing as these projects have already commenced and therefore cannot be deferred.

  Lowering the capital constraint would require EGI to reduce programs that directly maintain EGI's safe and reliable operations, for example:
    - Compliance driven work, including integrity management work and meter exchanges.
    - Program work with sufficient history and risk to warrant continuation, including AMP fitting replacements, inside regulator and ERR programs, distribution station replacement work, vehicle replacements and TIS infrastructure.
    - Investments prioritized through EGI's Risk Management Process (**Section 4.2**).
- Copperleaf was used to optimize the 1,500 EGD RZ investments and 1,901 Union RZ investments in the initial pre-optimized ask. Using the optimization constraint values, the optimal capital timing was determined for proposed investments, as described in **Section 4.3.3**.
- The Decision with Reasons in the St. Laurent Ottawa North Replacement Project (EB 2020-0293) led to two subsequent changes to this AMP to ensure that there was adequate time to collect condition information and consider risk implications – St. Laurent Phases 3 and 4 (see **Appendix A, Pg. 13 &14**), and Wilson Avenue Vintage Steel Replacement (see **Appendix A, Pg. 10**). Investments in the 10-year plan that had sufficient timing for further, cost

[37] Historical average spend was calculated using the average of the 2019-2021 actuals and 2022 forecast.

effective and prudent evaluation will continue to be assessed without prejudice to support the resultant investments. The LTC decision for St. Laurent is not expected to impact the Vintage Steel Replacement Program as this program and the associated selection of pipe replacements are based off of predictive analytics (condition and risk from the DIMP Risk Model as described in **Section 5.2.3.6.3.2**).

- The resultant capital plan was reviewed with internal stakeholders and endorsed by the Asset Management Steering Committee.

6.1.3 Optimization Results

The initial spend profile is reflective of the forecasted needs of the assets as identified through asset managers and investment owners. Copperleaf factors in both asset needs and capital optimization constraints to find an optimal capital portfolio.

The initial pre-optimized request for capital was $14.3B (see **Figure 6.1-1** and **Figure 6.1-2**). Because investments can shift in time during optimization, while overheads remain fixed, the annual capitalized overheads are treated as a separate investment during optimization. Once optimization is complete, overheads are applied to all investments and are reflected as such throughout this section. 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.

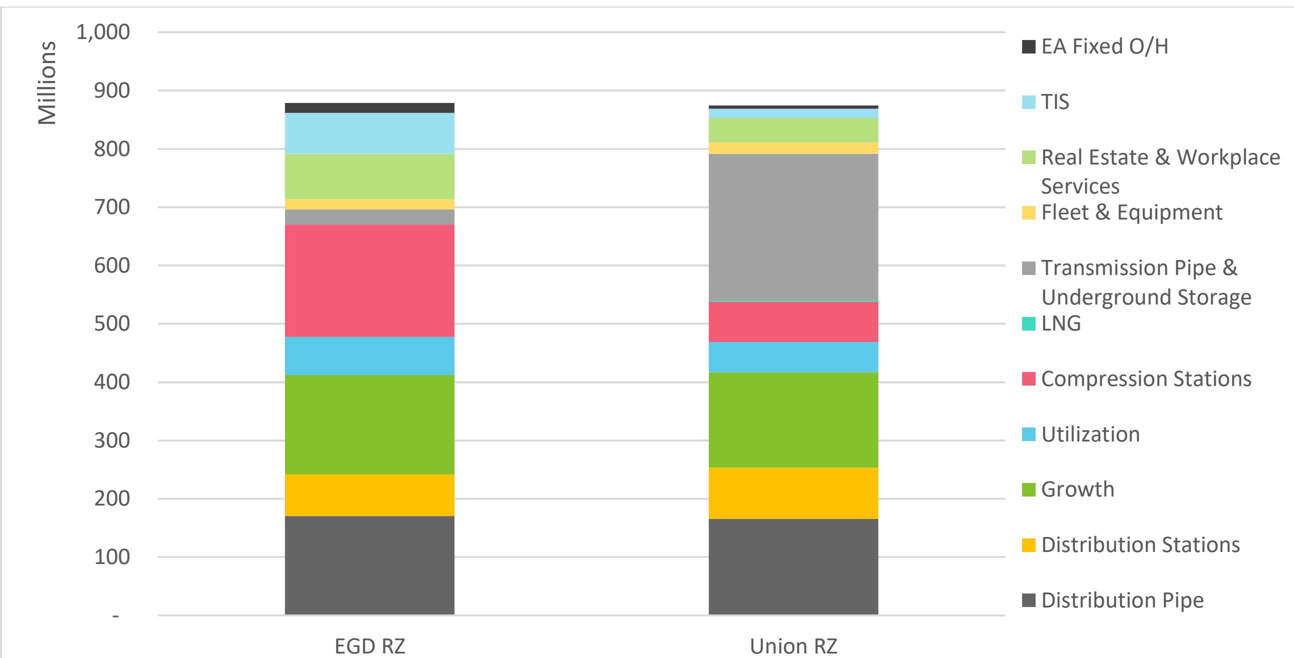


Figure 6.1-1: 2023 Pre-Optimized Spend Profile by Rate Zone (Capital Expenditure)

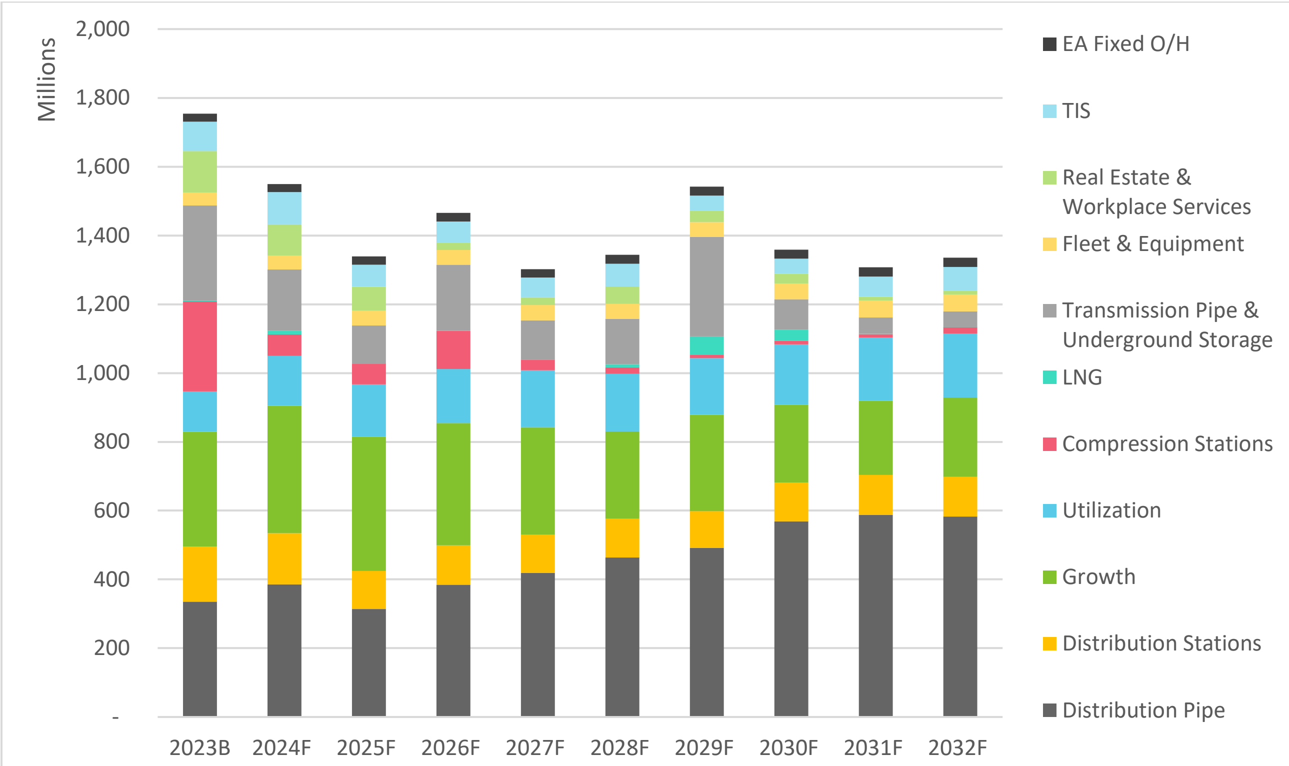


Figure 6.1-2: 2024-2032 Pre-Optimized Spend Profile – EGI (Capital Expenditure)

Prior to optimization, investments were categorized into planning groups (see **Table 6.1-1**) in Copperleaf based on asset management principles. This supported optimization activities where a different treatment (fixed or variable timing) could be applied to the investment groups at the time of optimization. For 2023, 92% of the capital had fixed timing, while approximately 8% had variable timing. For the remaining years, the capital with fixed timing ranged from 76%-92%.

Table 6.1-1: Planning Groups

Planning Group	Description	Optimization Treatment
Compliance – Fixed Timing	Investment meets criteria for compliance treatment (see **Table 4.1-2**)	Fixed timing
Mandatory – Fixed Timing	Investment meets criteria for mandatory treatment (see **Table 4.1-2**)	Fixed timing
Executing – Fixed Timing	Investment is in execution based on previously approved timing	Fixed timing
Compliance – Optimize	Investment meets criteria for compliance treatment but has flexibility in timing (see **Table 4.1-2**)	Optimized based timing constraint
Mandatory – Optimize	Investment meets criteria for mandatory treatment but has flexibility in timing (see **Table 4.1-2**)	Optimized based timing constraint
Executing Flagged for Optimize	Executing investments that could potentially have the remainder of the work shifted in timing	Timing optimized based on value
Value Driven – Value Framework	Value framework completed on the investment and not compliance, mandatory nor executing	Timing optimized based on value
Value Driven – Fixed Timing	Value framework completed on the investment and fixed timing required. Fixed timing for value driven investments may be required for multi-year	Fixed timing

Planning Group	Description	Optimization Treatment
	investments as it prevents Copperleaf from shifting all years into a single execution year.	
Overheads	Overheads	Fixed timing
Significant Investments (>$10M) – Value Driven	Investment is greater than $10M (net base capex). Value framework has been completed on the investment and not compliance, mandatory nor executing	Timing optimized based on value
Significant Investments (>$10M) – Fixed Timing	Investment is greater than $10M (net base capex). Compliance/mandatory requirements validated or executing.	Fixed timing

The capital plan was optimized from 2023 to 2032 using the Optimize Portfolio of Solutions step of the AIPM process (outlined in **Section 4.3.3**). While running the optimization at the defined capital constraints, an optimized solution could not be obtained. This was due to the capital profile of specific fixed and mandatory projects. To resolve this, investments that were likely to be causing the optimization runs to fail were removed from optimization (Dawn C Compression Lifecycle in 2026 [see **Appendix A, Pg. 3**] and the Dawn-Parkway Expansion [Dawn-Enniskillen] Project in 2029 [see **Appendix A, Pg. 53**]), providing EGI with the best understanding of an optimized typical base spend profile. These significant investments were brought back into the plan after optimization was rerun.

As described in **Section 4.3.3**, the optimized result and significant projects (Net Base Capex >$10M) were reviewed with all asset managers and business stakeholders. Adjustments were proposed to better align the plan to life-cycle strategies, opportunities to pursue integrated resource planning, resource balancing requirements, other external project dependencies (moratoriums), and the capital optimization constraint. Investments that were not properly time constrained in Copperleaf were adjusted to reflect more appropriate timing to support long term resource management. Updates for any significant projects were also reviewed and adjusted (for example St Laurent Phase 3/4 and Wilson Avenue). Adjustments were incorporated as necessary through consultation with asset managers and using the value framework for project comparison.

Overall, EGI removed an average of ~$100M/year over the 10-year plan. This reduction was achieved through using optimization to assign timing to investments in order to maximize the value of the portfolio and through reductions EGI made in consultation with internal stakeholders. The value-driven investments that were assigned timing outside of the 10-year window were primarily REWS property upgrades and replacements in the Distribution Pipe and LNG asset classes. The remaining reductions were achieved through review of the proposed capital for each asset class and comparing for alignment with the asset class strategy and to historical spend levels. EGI targeted programmatic spends that had flexibility in the number of years they could be executed over, some of the specific programs that were reduced include: STO Strategic land purchases, class location, corrosion, real estate and delaying the start of the vintage steel replacement program.

The portfolio of solutions exceeded the optimization constraint in years 2024, 2025 and 2026. In 2024, the optimization constraint was exceeded due to the following drivers: the updated timing of St. Laurent and Wilson Avenue to allow for further condition evaluation in response to the May 2022 LTC decision, the Dawn C Compression Lifecycle and the Dawn-Parkway Expansion (Kirkwall to Hamilton) projects started spending in 2024 (Dawn C Compression Lifecycle was treated as a significant investment); and the TIS investments required in 2024 to support EGI's rebasing. The optimization constraint was exceeded in 2025 due to the Dawn C Compression Lifecycle and the Dawn to Parkway Expansion (Hamilton-Kirkwall) projects, the customer-driven Hamilton Industrial Reinforcement project, and the timing of the Kelfield and Kennedy Road REWS investments. The optimization constraint in 2026 was exceeded due to the Dawn C Compression Lifecycle and the Dawn to Parkway Expansion (Hamilton-Kirkwall) projects and the timing of the Kelfield and New London Site REWS investments. **Figure 6.1-3** presents the 10-year capital requirements by asset class and the significant investments >$50M.

The result addresses the organization's baseline facility needs and includes known risks and opportunities requiring action over the next 10 years, the optimized 10-year request for capital was $13.3B. The optimized 10-year request includes 1,384 EGD RZ investments and 1,703 Union RZ investments, which relates to a reduction of 314 investments from the initial pre-optimized request.

The final 10-year portfolio of spend was reviewed and approved by the Vice President of Engineering and the Asset Management Steering Committee. The final 10-year capital plan reflects the current facility needs, as EGI completes the evaluation of investments through the IRP Assessment process, investments will be removed, reduced, or deferred where economically and technically feasible IRPAs are identified.

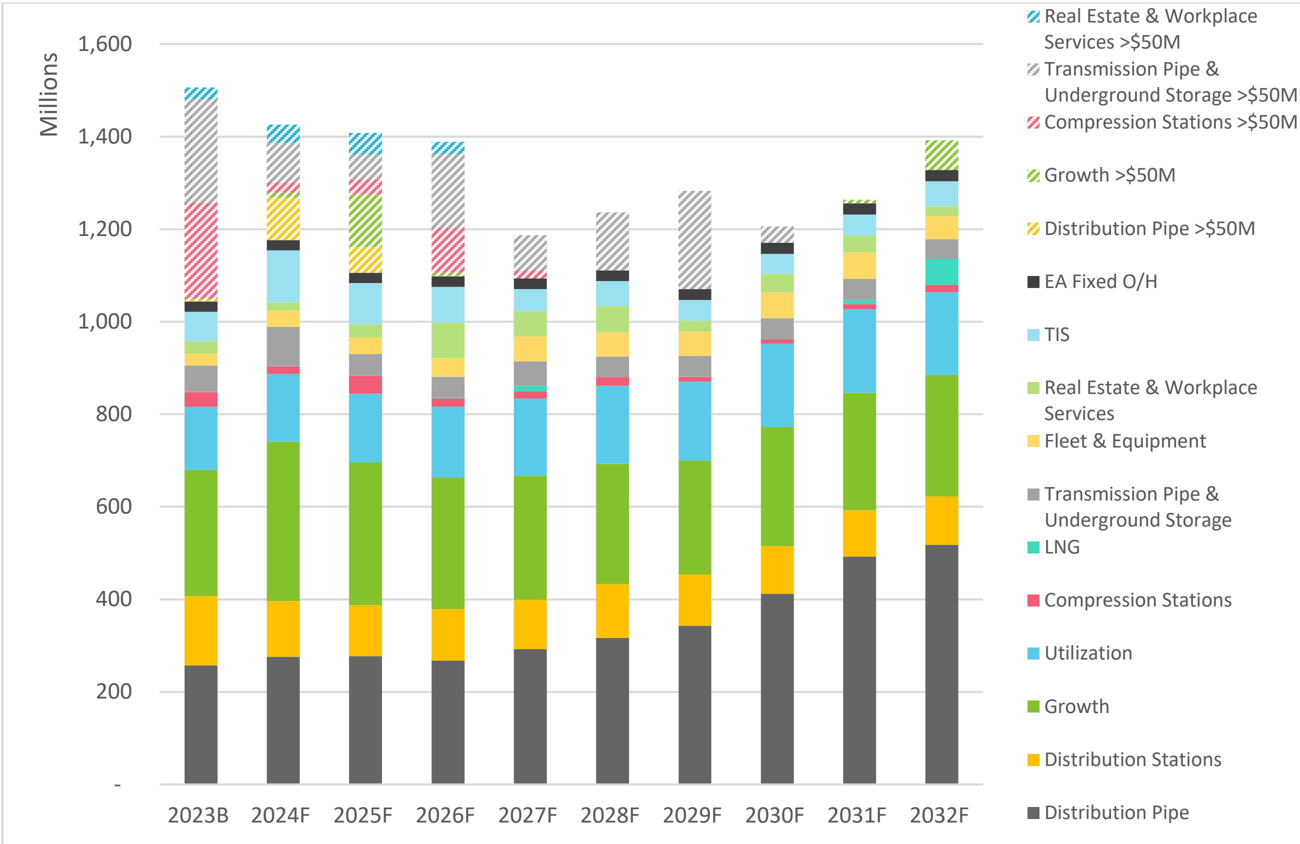


Figure 6.1-3: 10-Year Plan by Asset Class – EGI

6.2 Summary of Capital Expenditure

The capital profile is presented at an EGI level for 2023 to 2032 (see **Figure 6.2-1**). The direct 10-year capital profile for EGI from 2023 to 2032, totals approximately $13.3B in proposed asset expenditures. For 2023, the assets for the two RZs, EGD RZ and Union North and South RZs, were maintained separately for capital planning purposes. **Section 6.2.1** and **Section 6.2.2** show the 2023 capital profile and variance explanations for EGD and Union RZs respectively.

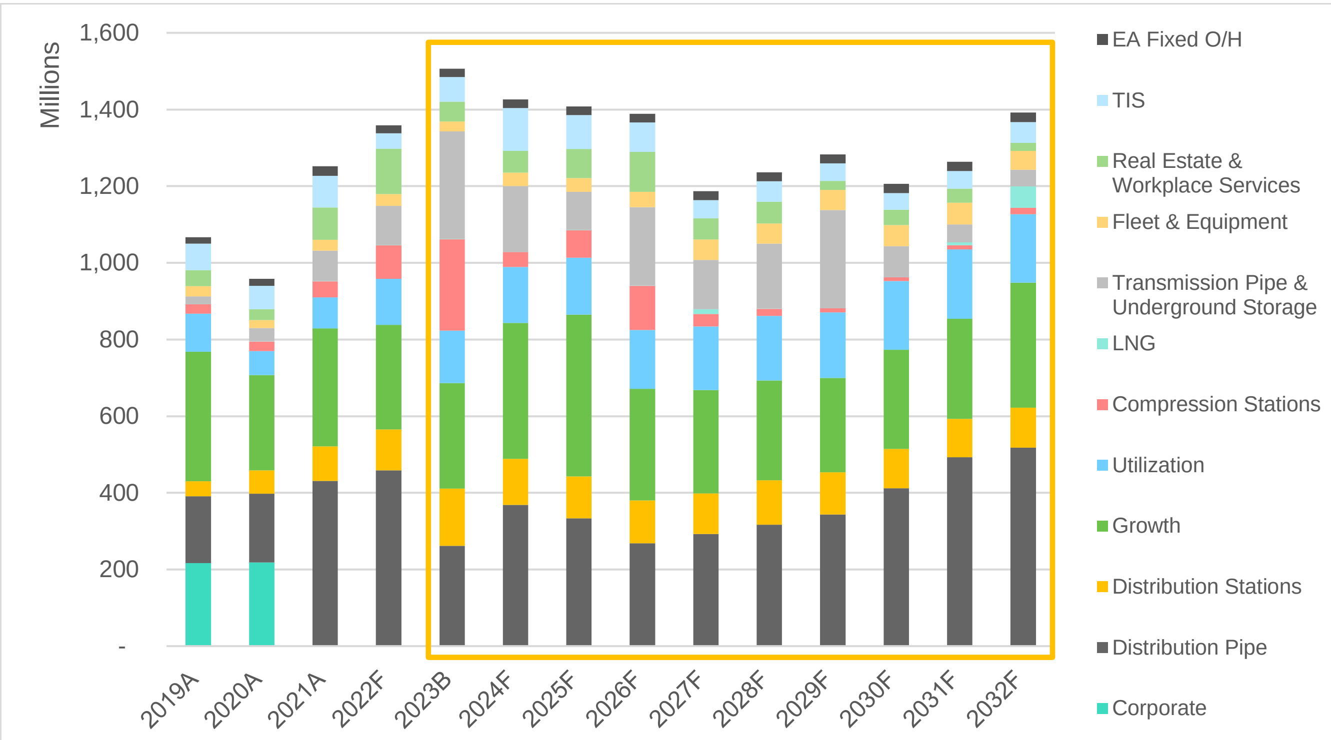


Figure 6.2-1: Capital Profile by Asset Class – EGI

Note: Historical actuals include Capital Pass Through (CPT) Mechanism, ICM projects and integration capital. The total forecasted capital expenditures categorized by asset class depicted in **Figure 6.2-1** are comprised of each investment's direct costs and the associated overheads. Asset class historical spend profiles in 2019 and 2020 do not include associated overheads; for this reason, overheads are identified as a separate category historically. Due to the timing of the 2022 Forecast data, the 2023 Budget and 2024 Forecast include investments that have shifted out of 2022 that are also captured in the 2022 Forecast, for example St. Laurent Ph 3/4.

6.2.1 Summary of 2023 Capital – EGD Rate Zone

Figure 6.2-2 shows the 2023 capital budget for EGD Rate Zone presented by asset class.

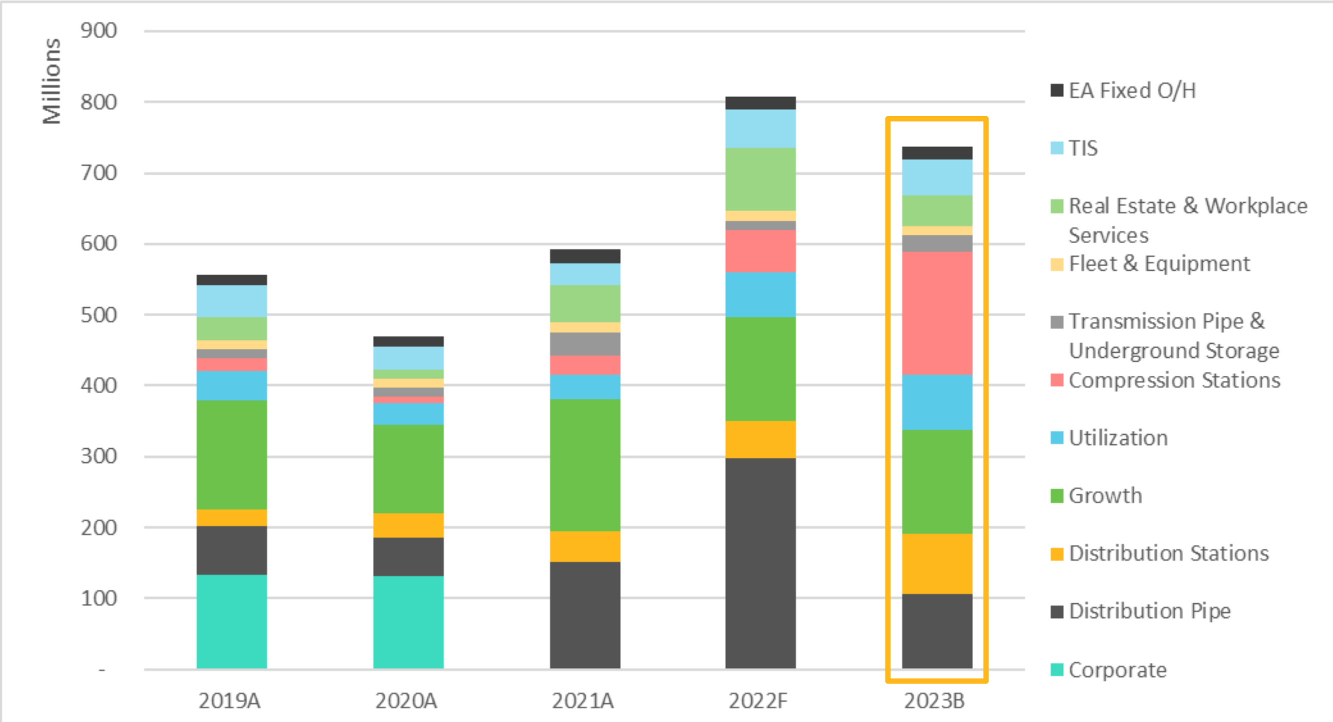


Figure 6.2-2: Capital Profile by Asset Class (2023) – EGD Rate Zone

Note: Historical actuals include Capital Pass Through (CPT) Mechanism, ICM projects and integration capital. The 2023B capital expenditures categorized by asset class depicted in **Figure 6.2-2** are comprised of each investment's direct costs and the associated overheads. Asset class historical spend profiles in 2019 and 2020 do not include associated overheads; for this reason, overheads are identified as a separate category historically. The 2022 Forecast Data was produced before EGI's 2023-2032 capital plan was created and before the St. Laurent LTC Decision (EB-2020-0293) was received, therefore, the St. Laurent Ph 3/4 projects are also shown in the 2022 Forecast.

Table 6.2-1 shows the 2023 forecast published in the 2021 – 2025 AMP (EB-2019-0194, Exhibit C, Tab 2, Schedule 1) and the proposed 2023 capital budget for the EGD RZ and lists any variance explanations. As discussed in **Section 4.3**, emerging and revised projects were identified and evaluated based on the existing 2023 portfolio. Updated cost estimates were prepared for new or revised 2023 projects.

Table 6.2-1: 2023 EGD Capital Budget and Variance Explanations (Includes Overheads)

Asset Class	2023 AMP	2023 Budget	Variance	Variance Explanation*

Growth	$159.8M	$147.0M	-$12.8M	• **-$4.5M** – Decreased customer connections forecast
				• **-$8.4M** – Changes in reinforcement timing and scope due to changes in the growth forecast:
				  • **-$9.3M** – Thornton XP Reinforcement
				  • **-$2.8M** – Brockville Gate Station
				  • **+$3.6M** – Huntmar Drive

Distribution Pipe	$109.9M	$106.5M	-$3.4M	• **+2.4M** – New integrity programs driven by third-party assessment results: Independent Asset Integrity Review (IAIR) and TIMP Geohazard Mitigation • **+$6.1M** – Increase to relocation program due to additional information available on relocations and adjustments to regional forecasts • **-$9.0M** – Various changes in cost, scope and timing in main replacements. The updated DIMP Risk Model shifted project timing for the Vintage Steel Replacements. • **-$3.0M** – Due to an increase in the AMP fitting program countered by a decrease in Service Relays anticipated by Regional workload forecasts

Distribution Stations	$40.2M	$84.1M	+$43.9M	• **-$600K** – ERR program complete
				• **-$3.1M** – Various changes to Station Rebuilds and B and C as project scope develops and projects are defined from programs
				• **+$47.0M** – Overall increase in Gate, Feeder and A Stations station due to:
				  • **+$23.4M** – Reclassification of Crowland Storage from Compression Station Asset Class to Distribution Stations Asset Class
				  • **+$15.6M** – Updated scope of Lisgar Station to address integrity and compliance concerns
				  • **+$10.6M** – Updated scope and cost for GTAW Parkway Gate Station Rebuild Ph 2
				  • **+$7.0M** – Successfully purchased land for relocation of St. John Sideroad Feeder Station
				  • **-$4.9M** – Change in scope and timing for Keele and Finch Feeder due to land availability
				  • **-$3.7M** – Bathurst Gate Station timing changed to 2025 to allow for permit acquisition

Utilization	$56.8M	$77.7M	+$20.9M	• **+$12.8M** – Increase in meters (maintenance) due to proactive meter replacement to smooth workload and increased cost of substitute meter due to supply chain delays • **-$3.2M** – Reduction in meters (growth) due to decrease in the growth forecast and a small adjustment to the allocation of meters growth/maintenance • **+$1.9M** – AMI Pilot project

Asset Class	2023 AMP	2023 Budget	Variance	Variance Explanation*
				• **+$9.2M** – Increase in regulator refit program driven by refinement of cost calculation.
Compression Stations	$59.3M	$174.0M	+$114.7M	• **-$16.4M** – Dehydration expansion project not required in 2023 • **-$18.5M** – Reclassification of Crowland Station Renewal to Distribution Stations asset class as preferred alternative operates without compression • **+$146.8M** – Dawn to Corunna (previously SCOR: K701/2/3 Reliability) pulled forward to 2023. • **+$3.4M** – SCOR:60004-Fdn Blk-Replace timing shifted from 2022 to 2023 execution
Transmission Pipe & Underground Storage	$10.1M	$22.7M	+$12.5M	• **+$2.5M** – New Independent Asset Integrity Review (IAIR) integrity remediation program • **+$1.9M** – NPS 20 Seckerton Gathering ECDA to ILI retrofit identified • **+$10.6M** – PCRW: Wells Upgrade advanced for construction efficiencies with Distribution Stations project • **-$2.6M** – No MOP-driven replacements identified for 2023
Fleet & Equipment	$11.8M	$12.5M	+$0.7M	• **+$0.7M** – Increase in fleet to meet vehicle replacement strategy
Real Estate & Workplace Services	$21.6M	$43.6M	+$22.0M	• **+$24.9M** – Variance due to tendered construction cost and delayed start for Station B with large portion of construction in 2023 • **-$2.3M** – Kennedy Rd. start date deferred to meet evolving business facility requirements

TIS	$30.8M	$50.7M	+$19.9M	• **+$23.1M** – Variance in TIS Business Solutions reflects evolving business needs including:
				  ◦ **+$2.5M** – Contract Market Harmonization
				  ◦ **+$5.6M** – Gas Recovery Harmonization
				  ◦ **+$9.3M** – Contract Market Systems - Technology Obsolescence
				  ◦ **+$2.5M** – Green Button
				  ◦ **+$2.5M** – ESRI GIS Version Upgrade 2023
				• **-$2.7M** – Microsoft Enterprise Agreement due to transition to cloud services (OPEX)

EA Fixed Overheads (O/H)	$15.5M	$17.6M	+$2.1M	• The variance reflects increases to alliance partner Fixed Overheads that began in 2020 but would not have been captured at the time the AMP 2021 – 2025 was developed.
Total	$515.9M	$736.4M	$220.5M	

*Instances where discrepancies exist between the Variance column and Variance Explanations are due to multiple immaterial changes (e.g., cost, scope, and timing) across the asset class.

Table 6.2-2 shows the 2022 Forecast compared to the proposed 2023 Capital Budget for the EGD Rate Zone Portfolio. Due to the timing of the 2022 Forecast data, the 2023 Budget may include investments that have shifted out of 2022 that are captured in the 2022 Forecast.

Table 6.2-2: 2022 Forecast vs 2023 EGD Capital Budget and Variance Explanations (Includes Overheads)

Asset Class	2022 Forecast	2023 Budget	Variance	Variance Explanation
Growth	$146.4	$147.0M	$0.6M	• Minor fluctuation in Customer Connections year over year • 2022 Hydrogen Powered CHP TOC project • Change in reinforcement timing and scope due to changes in the growth forecast
Distribution Pipe	$297.9M	$106.5M	-$191.5M	• Decrease in main replacements in 2023 due to large ICM-projects planned in 2022 including NPS 20 Lakeshore Replacement (Cherry to Bathurst), St. Laurent Ph 3 and timing of smaller investments • Variance in integrity due to project pacing and New Independent Asset Integrity Review (IAIR) integrity program • Increase in relocation projects based on adjustments to regional forecasts as scope was defined • Proactive service relay volumes increased as COVID-19 work restrictions return to normal
Distribution Stations	$53.0M	$84.1M	$31.1M	• Variance in Gate, Feeder and A stations due to large 2023 projects including Crowland Storage Transfer ($23.7M), Lisgar Station ($19.3) and GTAW Parkway Gate ($10.6M) and an overall increase in contractor and material costs
Utilization	$62.0M	$77.7M	$15.7M	• Increase due to proactive meter replacement to smooth workload and increased cost of substitute meter due to supply chain delays • Variance due to multiyear spend profile of AMI pilot project • Adjustments in regulator refits and meter installations due to alliance partner resource availability
Compression Stations	$60.2M	$174.0M	$113.8M	• Increased spend in 2023 primarily driven by Dawn to Corunna ($159.4M) • Decrease in 2023 due to 2022 timing of SCOR Meter Area Upgrade Ph 2 • Decrease in improvements compared to 2022, where 2022 investments include Crowland Station Renewal In Place and Corunna iBalance Upgrades and PSV upgrades

	2022 Forecast	2023 Budget	Variance	Variance Explanation
Transmission Pipe & Underground Storage	$12.8M	$22.7M	$9.8M	• Variance due to project pacing and scope of improvement projects • Increase in 2023 replacement projects due to Crowland Wells Upgrade project ($10.6M) • Increase in integrity due to New Independent Asset Integrity Review (IAIR) integrity program
Fleet & Equipment	$14.5M	$12.5M	-$2.0M	• Variance from 2022 tools program due to 2022 purchase tools including service abandonment tools and the ProStopp T.D. Williamson isolation tool which improves safety for workers during construction activities
Real Estate & Workplace Services	$78.0M	$43.6M	-34.4M	• Year over year variance is due to market availability of land and project scope variation to meet evolving business facility requirements • A specific example was the anticipated purchase of land to replace the Kelfield facility in 2022

TIS	$28.3M	$50.7M	$22.4M	• **+$23.3M** - Variance in TIS Business Solutions reflects evolving business needs including:
				  • **+$9.3M** - Contract Market Harmonization
				  • **+$5.7M** - Gas Recovery Harmonization
				  • **+$9.3M** - Contract Market Systems - Technology Obsolescence
				  • **+$2.5M** - Green Button
				  • **+$2.5M** - ESRI GIS Version Upgrade 2023

EA Fixed O/H	$16.9M	$17.6M	+$0.7M	• Variable based on workload and performance
Total	$770.1M	$736.4M	-$33.7M	

6.2.2 Summary of 2023 Capital – Union Rate Zones

Figure 6.2-3 shows the 2023 capital budget for Union RZs presented by asset class.

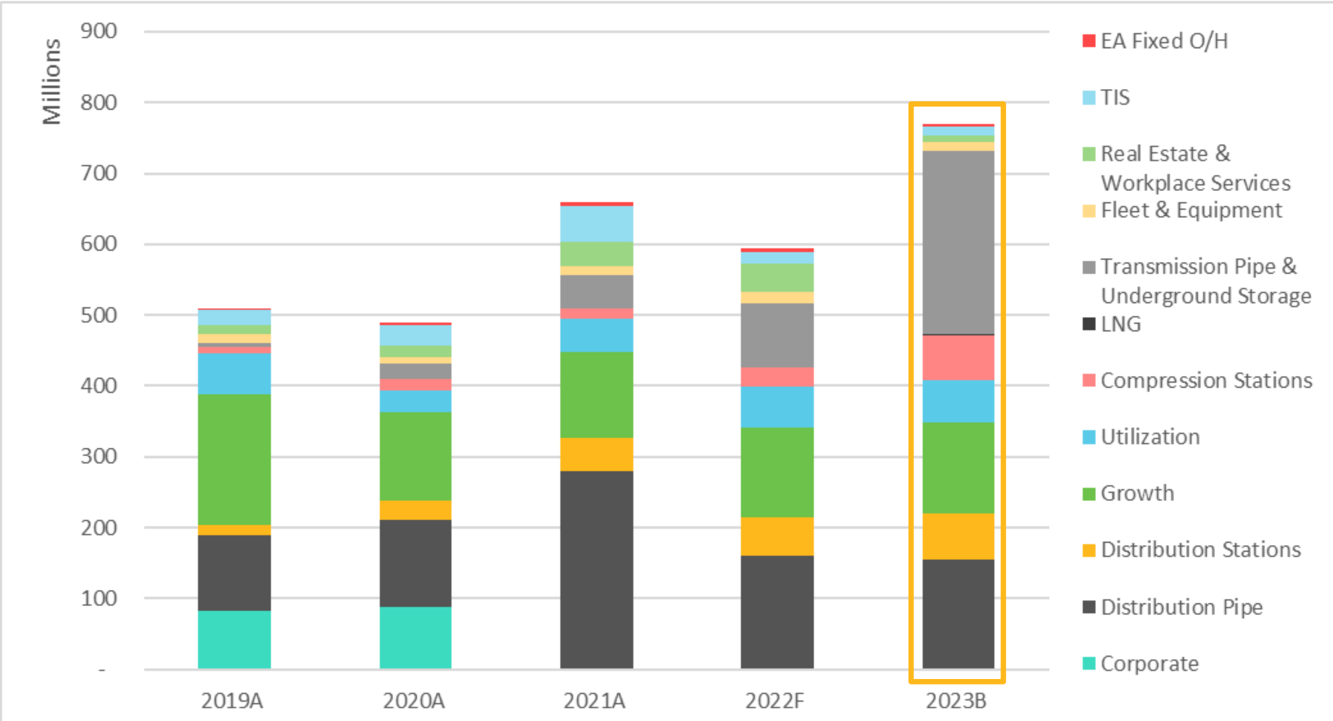


Figure 6.2-3: Capital Profile by Asset Class (2023) – Union Rate Zones

Note: Historical actuals include Capital Pass Through (CPT) Mechanism, ICM projects and integration capital. The 2023B capital expenditures categorized by asset class depicted in **Figure 6.2-3** are comprised of each investment's direct costs and the associated overheads. Asset class historical spend profiles in 2019 and 2020 do not include associated overheads; for this reason, overheads are identified as a separate category historically.

Table 6.2-3 shows the 2023 forecast published in the 2021 – 2025 AMP (EB-2019-0194, Exhibit C, Tab 2, Schedule 1) and the proposed 2023 capital budget for the Union RZs and lists any variance explanations. As discussed in **Section 4.3**, emerging and revised projects were identified and evaluated based on the existing 2023 portfolio. Updated cost estimates were prepared for new or revised 2023 projects.

Table 6.2-3: 2023 Union Capital Budget and Variance Explanations (Includes Overheads)

Asset Class	2023 AMP	2023 Budget	Variance	Variance Explanation*

Growth	$207.4M	$128.3M	-$79.1M	• Minor fluctuation in customer connections to better reflect actual costs
				• **-$86.6M** – Changes in reinforcement timing and scope due to changes in the growth forecast including:
				  ◦ **+6.1M** - Staples 1A Panhandle Distribution Reinforcement
				  ◦ **+5.7M** – Hensall Trans Station Rebuild
				  ◦ **+4.2M** – Kingston Creekford Rd Reinforcement
				  ◦ **-$66.3M** – SRP North Sudbury Marten River Compressor Station
				  ◦ **-$19.3M** – Parry Sound Lateral Reinforcement (12.5 km of NPS 6)
				  ◦ **-$10.5M** – Cambridge Reinforcement
				  ◦ **-$8.0M** – Oxford Phase 2, Delhi Reinforcement
				• **+$2.1M** – New EGI Hydrogen blending feasibility investments

Distribution Pipe	$122.2M	$155.5M	+$33.2M	• **-$9.0M** - Class Location work previously classified under main replacements; decrease aligns with sustainment workloads of program.
				• **-$2.6M** – Decrease driven by updated anode program workload forecast
				• **+$45.8M** – Variance in integrity management projects and programs including:
				  ◦ **+$15.6M** – New integrity programs driven by 3rd party assessment results: Independent Asset Integrity Review (IAIR)
				  ◦ **+$7.5M** – Depth of Cover Mitigation Program
				  ◦ **+3.0M** – TIMP Geohazard Mitigation
				  ◦ **$12.5M** – Sudbury lateral integrity digs
				• **-$0.8M** – Decrease to relocation program due to additional information available on relocations and adjustments to regional forecasts.
				• **+$7.0M** – Various changes in cost, scope and timing for main replacements and new cost for Private Sewer Lateral Locates ($1.2M)
				• **-$2.8M** – Decrease in Service Relays based on adjustments to regional forecasts
				• **-$6.4M** – No MOP-replacements have been identified for 2023.

Asset Class	2023 AMP	2023 Budget	Variance	Variance Explanation*

Distribution Stations	$25.2M	$64.4M	+$39.2M	• **+$2.1M** – Variance in CNG projects due to scope and cost definition
				• **+$11.8M** – Overall increase in Gate, Feeder and A Stations due to:
				  ◦ **+$3.1M** – Port Stanley Gate Station in plan due to operational and integrity concerns
				  ◦ **+$2.5M** – New Fire Suppressions and Auto Transfer Generator program driven by compliance requirements
				  ◦ **+$2.5M** – Hamilton Gate 3 in plan due to operational and integrity concerns
				  ◦ **+$1.0M** – Bryanston Gate in plan due to operational and integrity concerns
				• **+3.8M** – New Inside Regulator & ERR Program
				• **+$22.3M** – Overall increase in Station Rebuilds & B and C Stations due to project scope and timing including:
				  ◦ **+$9.2M** – 16U-601 Brantford Gate Station
				  ◦ **+$2.1M** – Goldcorp Dome Mine SMS Rebuild
				  ◦ **+$1.5M** – Sandwich Station reclassified to distribution stations from compression stations asset class
				  ◦ **+2.1M** – Dryden TBS, Glycol and Odourant Upgrades
				  ◦ **+$1.4M** – New Pressure Factor Measurement (PFM) compliance program
				  ◦ Various investments to address integrity and operational concerns.

Utilization	$61.0M	$58.8M	-$2.2M	• No significant variance

Compression Stations	$98.2M	$64.5M	-$33.7M	• **+7.2M** – Variance in improvement projects timing and scope including:
				  ◦ **+$2.3M** – 5985 CV & Piping- pipe modifications and inclusion filtration in design
				  ◦ **+$1.2M** – Parkway East Generator Control Upgrade due to unforeseen obsolescence
				  ◦ **+$1.0M** – Siemen's valve controller replacements
				• **-$2.9M** – Timing of Bright B Generator overhaul shifted to 2025 based on operating hours
				• **+47.9M** – Dawn to Corunna (Dawn Tie-in), Union Rate Zone component of Dawn to Corunna Pipeline project
				• **-$89.2M** – Timing of Dawn C Compression Lifecycle shifted to 2026

LNG	$16.0M	$0.8M	-$15.3M	• **-$16.0M** – Variance due to timing shift of Hagar replacement projects: JVG Compressor Upgrade and KVGR/Cycle Mix Cooler based on condition and risk

Asset Class	2023 AMP	2023 Budget	Variance	Variance Explanation*
Transmission Pipe & Underground Storage	$61.1M	$255.0M	+$193.9M	• **+$3.9M** – Class Location increase due to timing of execution • **+$223.6M** – Panhandle Regional Expansion Project driven by Panhandle Transmission System demand • **+$3.6M** – New Independent Asset Integrity Review (IAIR) integrity remediation program • **+$6.4M** – Due to the cost of replacing and remediating shallow depth of cover in six sections on the Trafalgar NPS 26 • **+$2.5M** – Due to the cost of retrofitting the NPS 24 Trafalgar Bypass Retrofit from ECDA to ILI inspection • **-$29.8M** – Panhandle Line Replacement in-service date shifted to 2024
Fleet & Equipment	$12.8M	$13.0M	+$0.2M	• No significant variance
Real Estate & Workplace Services	$26.3M	$8.5M	-$17.7M	• **-$17.3M** – New London Site and 50 Keil Drive Renovations Phase 4 start date deferred to meet evolving business facility requirements
TIS	$14.2M	$13.0M	-$1.1M	• No significant variance
EA Fixed O/H	$3.1M	$4.1M	+$0.9M	• Variable based on workload and performance
Total	$647.5M	$769.7M	$122.1M	

*Instances where discrepancies exist between the Variance column and Variance Explanations are due to multiple immaterial changes (e.g., cost, scope, and timing) across the asset class.

Table 6.2-2 shows the 2022 Forecast compared to the proposed 2023 Capital Budget for the Union Rate Zones Portfolio. Due to the timing of the 2022 Forecast data, the 2023 Budget may include investments that have shifted out of 2022 that are captured in the 2022 Forecast.

Table 6.2-4: 2022 vs 2023 Union Capital Budget and Variance Explanations (Includes Overheads)

Asset Class	2022	2023 Budget	Variance	Variance Explanation
Growth	$126.9M	$128.3M	$1.3M	• New EGI Hydrogen blending feasibility investments ($2.1M) partially offset by variance in customer connections (600K) • Minor fluctuation in Customer Connections year over year
Distribution Pipe	$160.6M	$155.5M	-$5.1M	• Overall increase due to the uptick in integrity programs driven by new IAIR program, new TIMP Geohazard Mitigation program and increase in integrity dig mitigation costs to address ILI results • Increase in relocations based on adjustments to regional forecasts as scope was defined • Decrease in main replacement program due to larger ICM projects executed in 2022 including London Lines, Kirkland Lake and timing and scope of smaller investments • Class Location program lower than 2022 due to initial ramp up of class location program entering sustainment phase • Decrease in corrosion program due to adjusted timing of rectifier groundbed program and forecast updates
Distribution Stations	$53.6M	$65.2M	$11.6M	• Net increase due to Inside Regulator & ERR Program and uptick in Station Rebuilds & B and C Stations due to new PFM Compliance Program, LP Station rebuilds and operational integrity concerns • Overall increase in contractor and material costs
Utilization	$58.3M	$58.8M	$0.5M	• No significant variance
Compression Stations	$26.9M	$64.5M	$37.6M	• Overall increase driven primarily by 2023 Dawn to Corunna (Dawn Tie In) project. • Decreases due to no major overhauls scheduled in 2023
LNG	$600K	$750K	$150K	• No change to the number of projects, minor variation in project cost
Transmission Pipe & Underground Storage	$89.7M	$258.0M	$168.4M	• Increase in 2023 due to Panhandle Regional Expansion Project ($205.6M) and Leamington Interconnect ($15M) • Decrease from 2022 integrity spend due to 2022 Dawn to Cuthbert (NPS 42, 34, 26) integrity investments
Fleet & Equipment	$16.1M	$13.0M	-$3.1M	• Fewer vehicle purchases planned in 2023 due to delays in supply chain

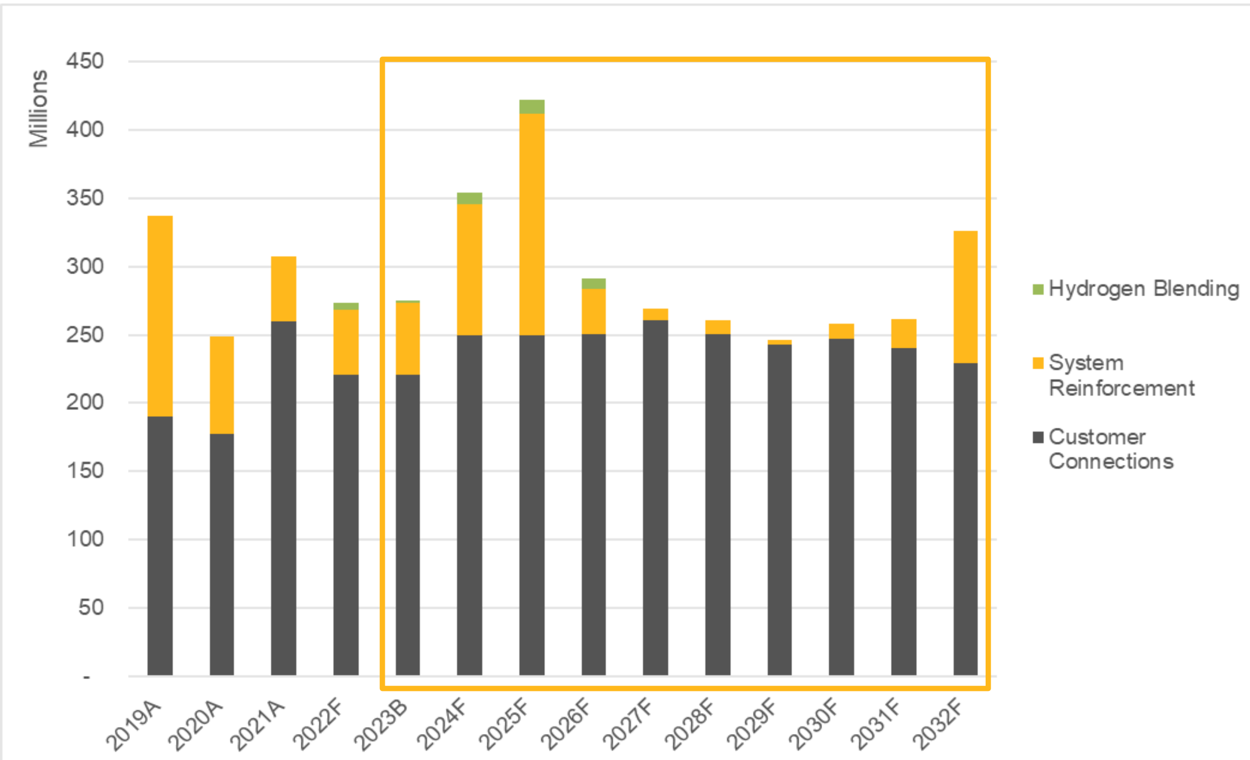
Asset Class	2022	2023 Budget	Variance	Variance Explanation
Real Estate & Workplace Services	$40.7M	$8.5M	-$32.1M	• Variance due to market availability and project scope variation to meet business facility requirements • Development timing of large projects such as New London Site and interior renovations at 50 Keil Drive
TIS	$11.1M	$13.0M	$1.9M	• Variance due to changing business requirements/timing
EA Fixed O/H	$4.5M	$4.1M	-$0.4M	• Variable based on workload and performance
Total	$588.9M	$769.7M	$180.8M	

6.2.3 Asset Class Capital Summaries

Variations in spend profiles are tied to the Asset Class Strategies described in **Section 5** and the variance explanations noted in **Sections 6.2.1 and 6.2.2**. The 2022 Forecast Data was produced before EGI's 2023-2032 capital plan was created; therefore, some investments are captured in both the 2022 Forecast Data and the subsequent years' budget.

6.2.3.1 Growth

The total average capital spend for the Growth asset class is forecast to be $296M over the 10 years identified. **Figure 6.2-4**. presents 4 years of historical spend and the projected 10-year EGI spend profile.



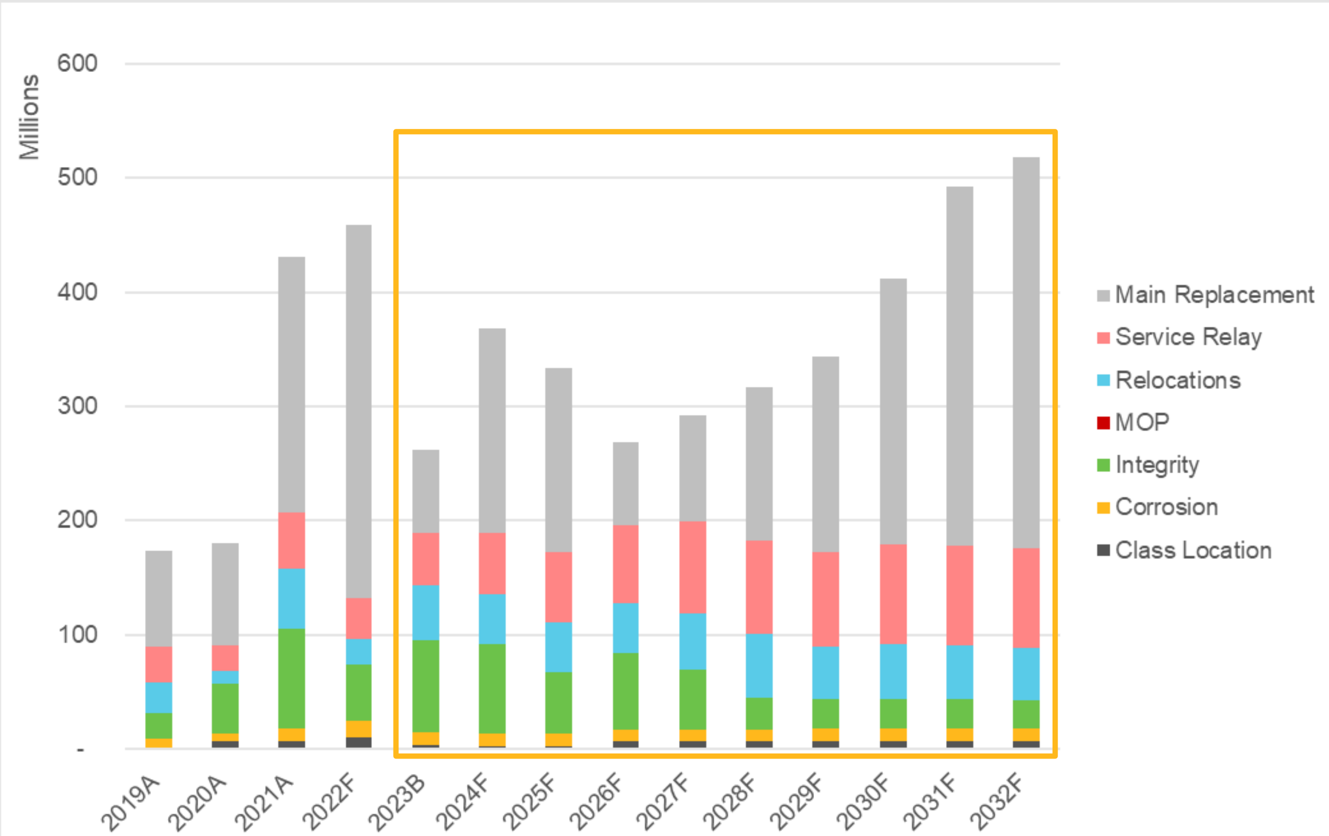
Note: *Overheads excluded in 2019 – 2020.*

Figure 6.2-4: Capital Expenditure over Time for Growth – EGI

For further details on the Growth asset class, refer to **Section 5.1**.

6.2.3.2 Distribution Pipe

The total average capital spend for the Distribution Pipe asset class is forecast to be $361M over the 10 years identified. **Figure 6.2-5** presents 4 years of historical spend and the projected 10-year spend profile. The 2022 Forecast Data was produced before EGI's 2023-2032 capital plan was created and before the St. Laurent LTC Decision (EB-2020-0293) was received, therefore, the St. Laurent Ph 3/4 projects are also shown in the 2022 Forecast.



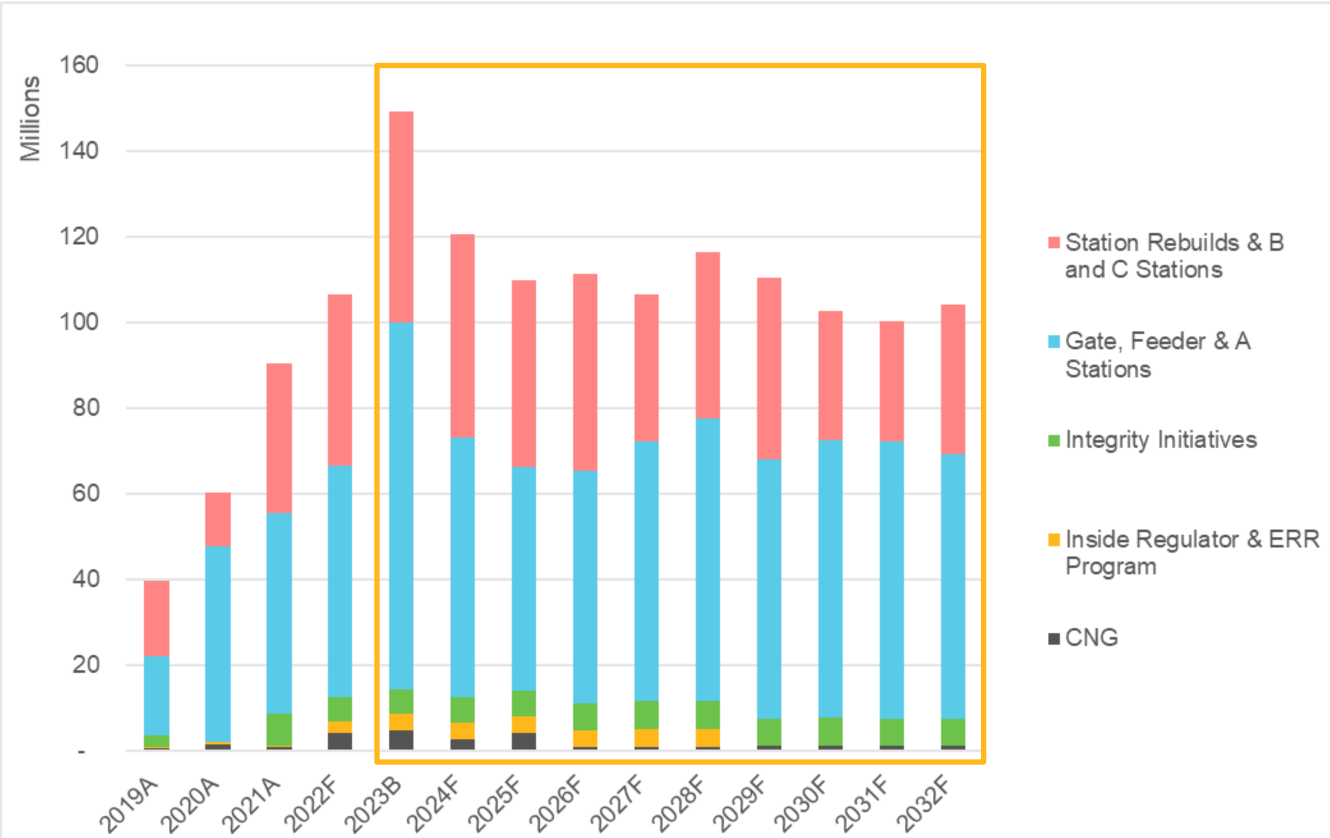
Note: *Overheads excluded in 2019 – 2020.*

Figure 6.2-5: Capital Expenditure over Time for Distribution Pipe – EGI

For further details on the Pipe asset class, refer to **Section 5.2.3**.

6.2.3.3 Distribution Stations

The total average capital spend for the Distribution Stations asset class is forecast to be $113M over the 10 years identified. **Figure 6.2-6** presents 4 years of historical spend and the projected 10-year spend profile**.**



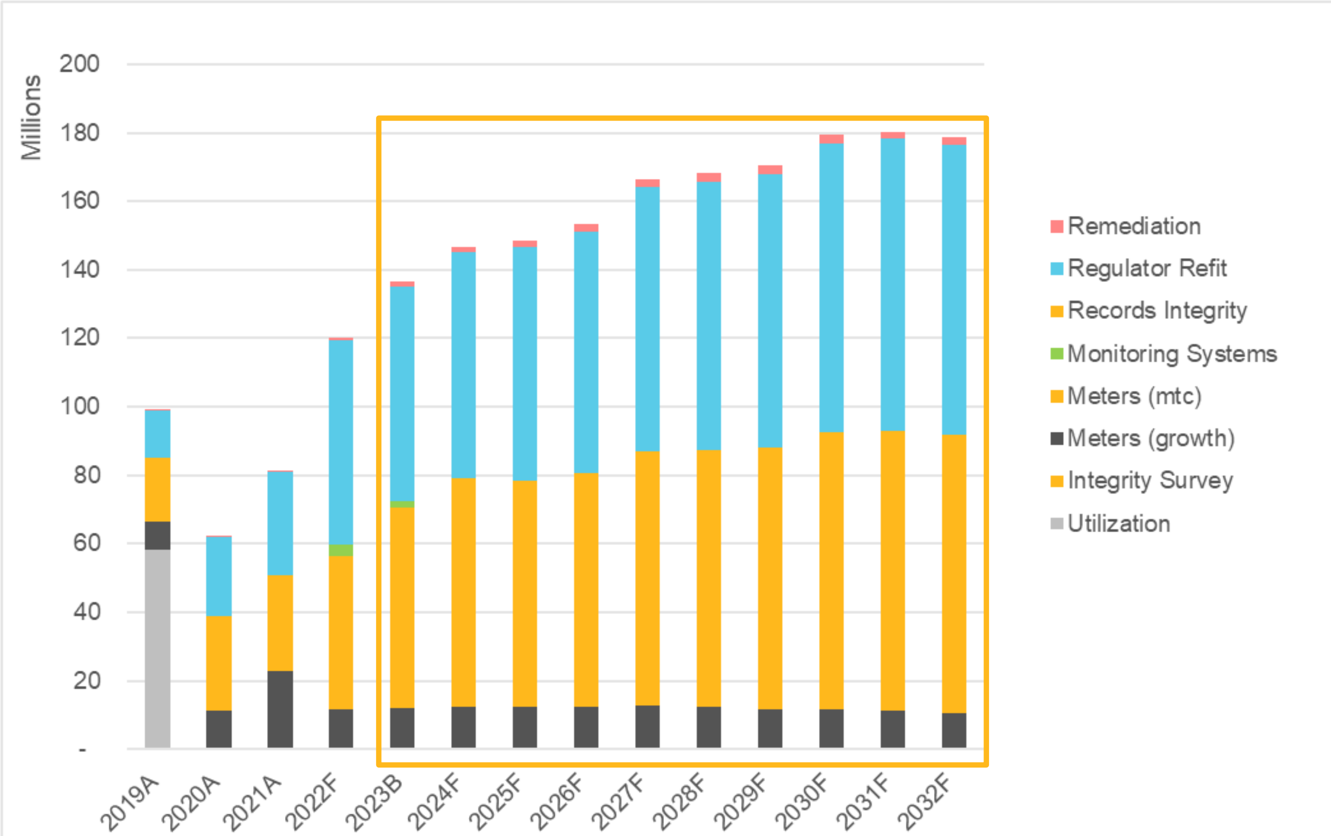
Note: *Overheads excluded in 2019 – 2020.*

Figure 6.2-6: Capital Expenditure over Time for Distribution Stations – EGI

For further details on the Distribution Stations asset class, refer to **Section 5.2.4**.

6.2.3.4 Utilization

The total average capital spend for the Utilization asset class is forecast to be $163M over the 10 years identified. **Figure 6.2-7** presents 4 years of historical spend and the projected 10-year spend profile**.**



Note: *Overheads excluded in 2019 – 2020.*

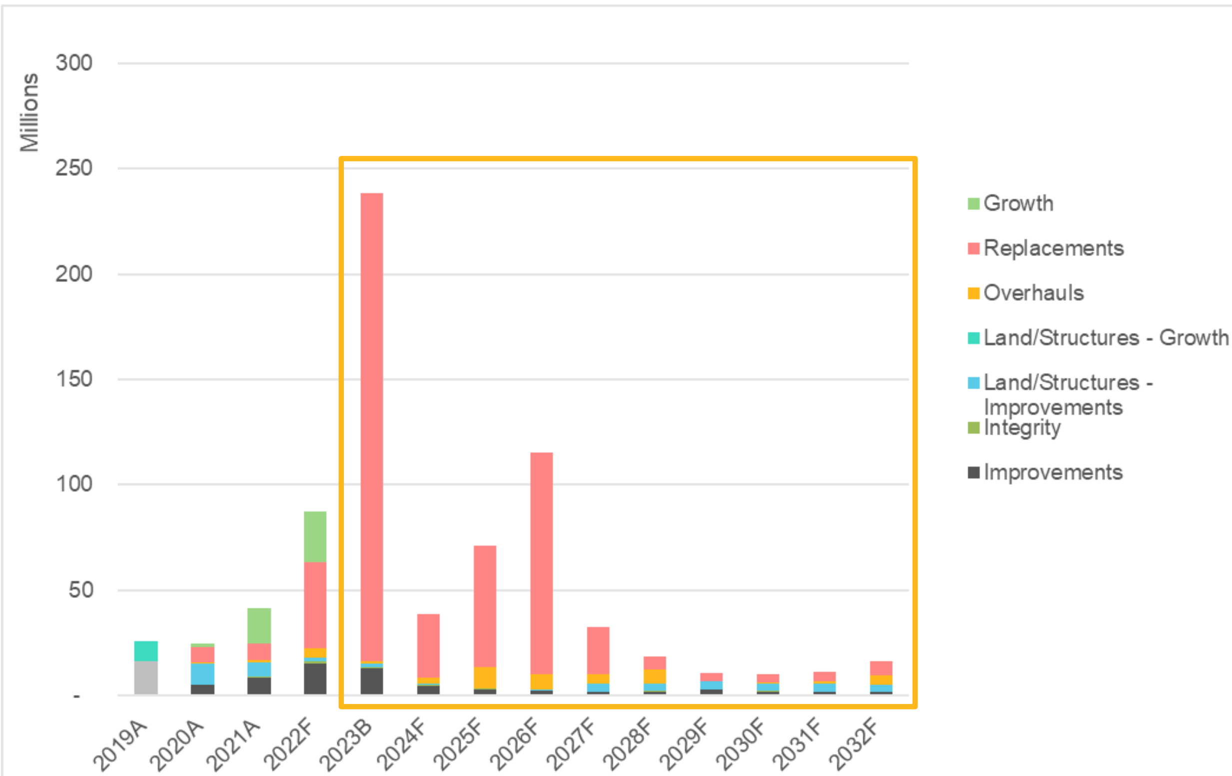
Figure 6.2-7: Capital Expenditure over Time for Utilization – EGI Rate Zone

For further details on the Utilization asset class and life cycle strategies, refer to **Section 5.2.5**.

6.2.3.5 Compression Stations

The total average capital spend for the Compression Stations asset class is forecast to be $56M over the 10 years identified.

Figure 6.2-8 presents 4 years of historical spend and the projected 10-year spend profile.



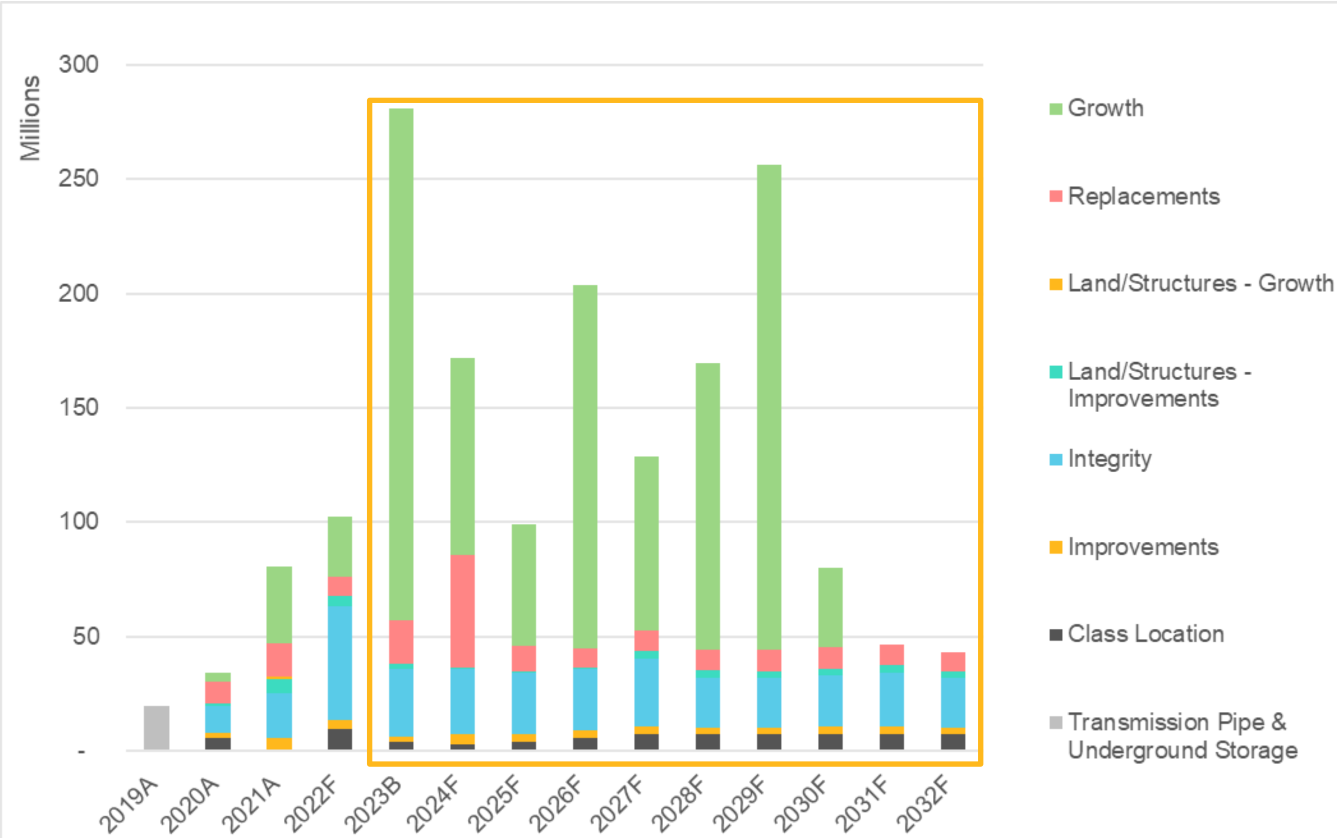
Note: *Overheads excluded in 2019 – 2020.*

Figure 6.2-8: Capital Expenditure over Time for Compression Stations – EGI

For further details on the Compression Stations asset class, refer to **Section 5.3.5**.

6.2.3.6 Transmission Pipe and Underground Storage

The total average capital spend for the Transmission Pipe and Underground Storage asset class is forecast to be $149M over the 10 years identified. The Transmission Pipe and Underground Storage class includes transmission reinforcement investments. **Figure 6.2-9** presents 4 years of historical spend and the projected 10-year spend profile**.**



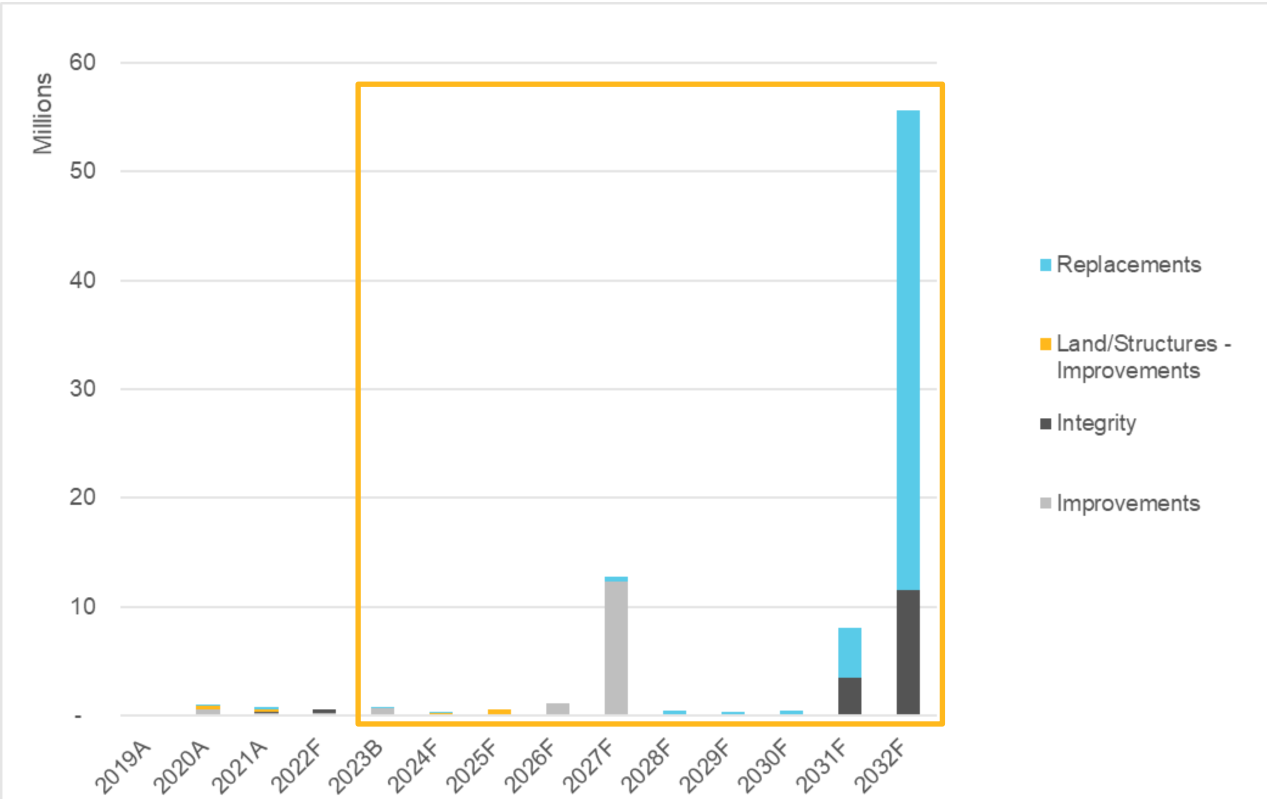
Note: *Overheads excluded in 2019 – 2020.*

Figure 6.2-9: Capital Expenditure over Time for Transmission Pipe and Underground Storage – EGI

For further details on the Transmission Pipe and Underground Storage asset class, refer to **Section 5.3.6**.

6.2.3.7 Liquefied Natural Gas

The total average capital spend for the Liquified Natural Gas (LNG) asset class is forecast to be $8M over the 10 years identified. **Figure 6.2-10** presents 4 years of historical spend and the projected 10-year spend profile**.** LNG assets are in the Union RZ only.



Note: *Overheads excluded in 2019 – 2020.*

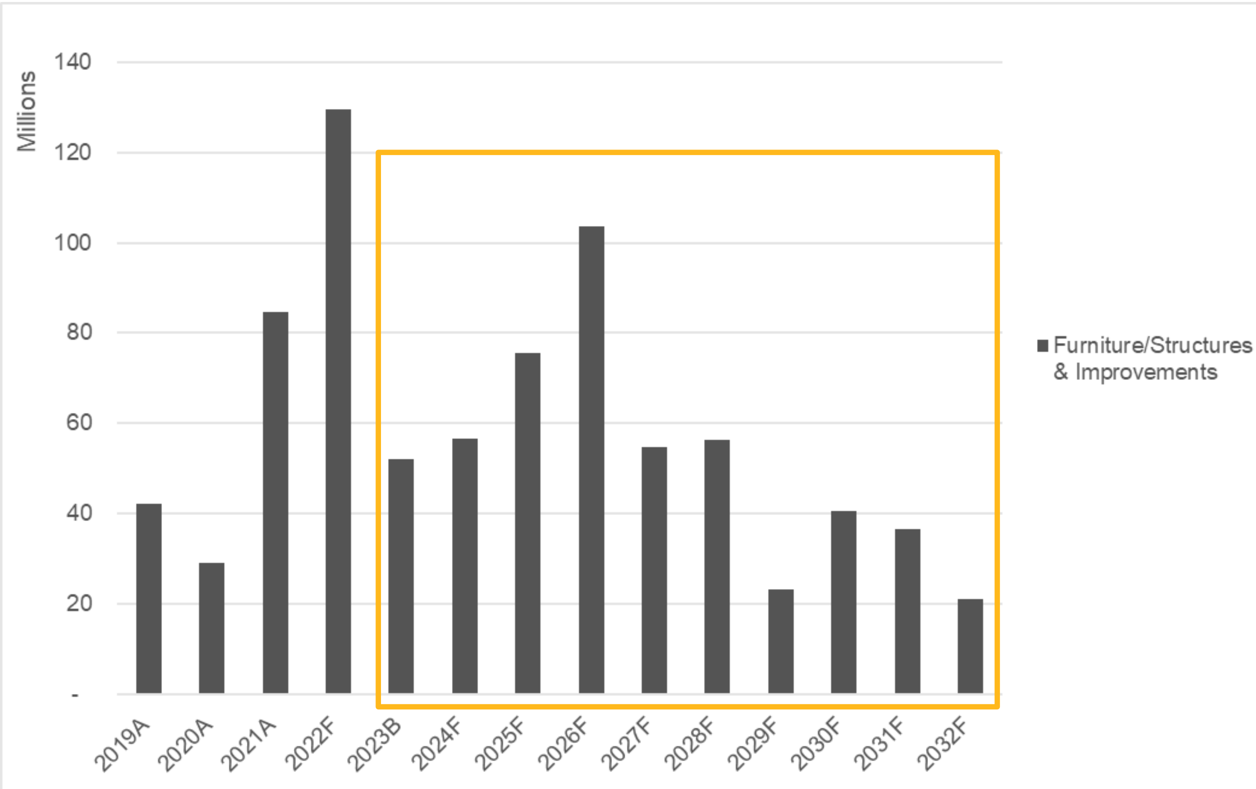
Figure 6.2-10: Capital Expenditure over Time for Liquefied Natural Gas – EGI

For further details on the LNG asset class, refer to **Section 5.3.7**.

6.2.3.8 Real Estate and Workplace Services

The total average capital spend for the Real Estate and Workplace Services (REWS) asset class is forecast to be $52M over the 10 years identified.

Figure 6.2-11 presents 4 years of historical spend and the projected 10-year spend profile**.**



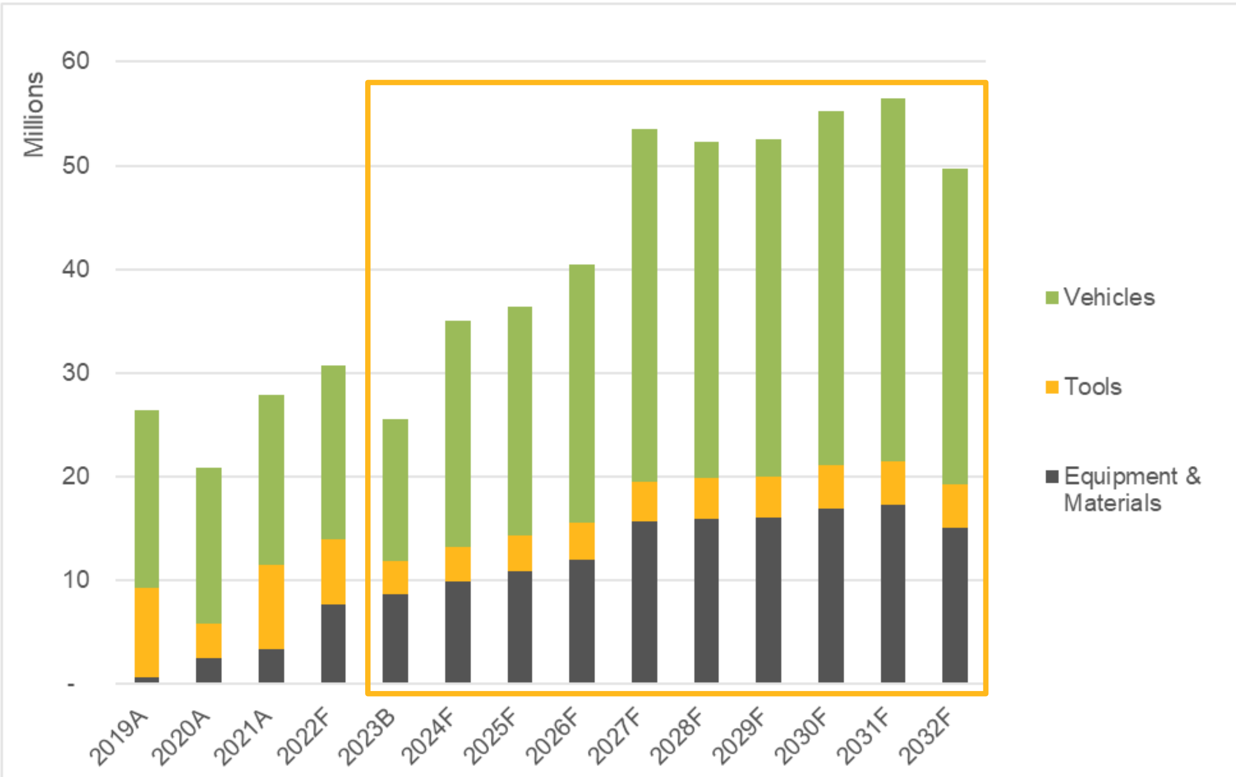
Note: *Overheads excluded in 2019 – 2020.*

Figure 6.2-11: Capital Expenditure over Time for REWS – EGI

For further details on the REWS asset class, refer to **Section 5.4**.

6.2.3.9 Fleet and Equipment

The total average capital spend for the Fleet and Equipment asset class is forecast to be $46M over the 10 years identified. **Figure 6.2-12** presents 4 years of historical spend and the projected 10-year spend profile**.**



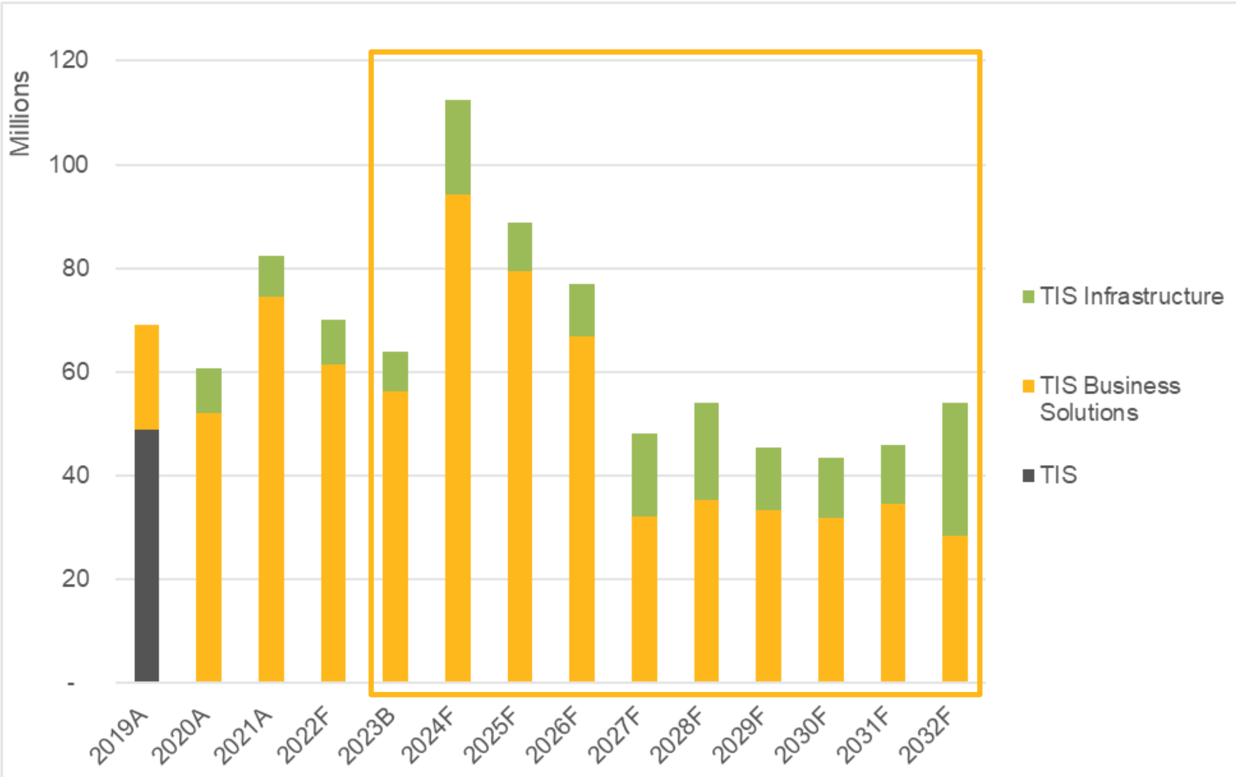
Note: *Overheads excluded in 2019 – 2020.*

Figure 6.2-12: Capital Expenditure over Time for Fleet and Equipment – EGI

For further details on the Fleet and Equipment asset class, refer to **Section 5.5**.

6.2.3.10 Technology and Information Services

The total average capital spend for the Technology and Information Services (TIS) asset class is forecasted to be $63M over the 10 years identified. **Figure 6.2-13** presents 4 years of historical spend and the projected 10-year spend profile**.**



Note: *Overheads excluded in 2019 – 2020.*

Figure 6.2-13: Capital Expenditure over Time for TIS – EGI

For further details on the TIS asset class, refer to **Section 5.6**.

6.3 Summary of IRP Assessment

This section provides detail on the methodologies and process used for IRP evaluation, the evaluation status and next steps. **Appendix B** provides additional detail on the scope and the current status of EGI's IRP assessment process, including the binary screen and IRPA evaluation status at the time of filing this AMP.

6.3.1 IRP Assessment Results

The 2023 – 2032 capital plan contains 3087 investments. For each investment included within **Appendix B**, the following sequence of steps are followed; where an investment is classified as either pass or fail at each stage. When an investment fails, it does not proceed to the next stage of evaluation as it is determined that an investment is not applicable for an IRPA.

Identification of Constraints - EGI implements a wide range of investments over a 10-year period, they are split between gas carrying asset investments and non-gas carrying asset investments. IRPAs are focused on gas carrying assets, therefore the initial step applied in the review of the 2023-2032 capital plan for IRP purposes, is to remove non-gas carrying assets.

Binary Screening – The binary screening criteria are then applied to all remaining projects. This step allows EGI to focus on investments where there is potential that an IRPA could technically and economically meet the system need. The binary screening was performed in accordance with the criteria outlined in the OEB's IRP Decision (EB-2020-0091).

Technical Evaluation – A technical evaluation is then performed on all projects that pass the binary screening. This step evaluates the technical viability of potential IRPAs to reduce peak demand to the degree required to meet the identified system need.

Economic Evaluation – An economic evaluation is then performed on all projects that pass the technical evaluation. This three-phase DCF+ evaluation compares the IRP Plan(s) to the facility alternative to determine which alternative is optimal. (See the OEB's IRP Decision [EB-2020-0091] for more details)

IRP Plan Application – When EGI determines that an IRPA (alone, in combination with other IRPAs, or in combination with a facility project) is the best option to address a system need, an application for approval of an IRP Plan will be submitted. Appendix B will indicate which investments have an associated IRP Plan and the status of the plan.

6.3.2 Identification of Constraints

Of the 3087 projects within the 2023-2032 capital plan, there were 809 non-gas carrying investments and 2278 gas carrying investments. **Figure 6.3-1** shows the associated costs for Gas Carrying and Non-Gas Carrying asset investments for the 2023 – 2032 period.

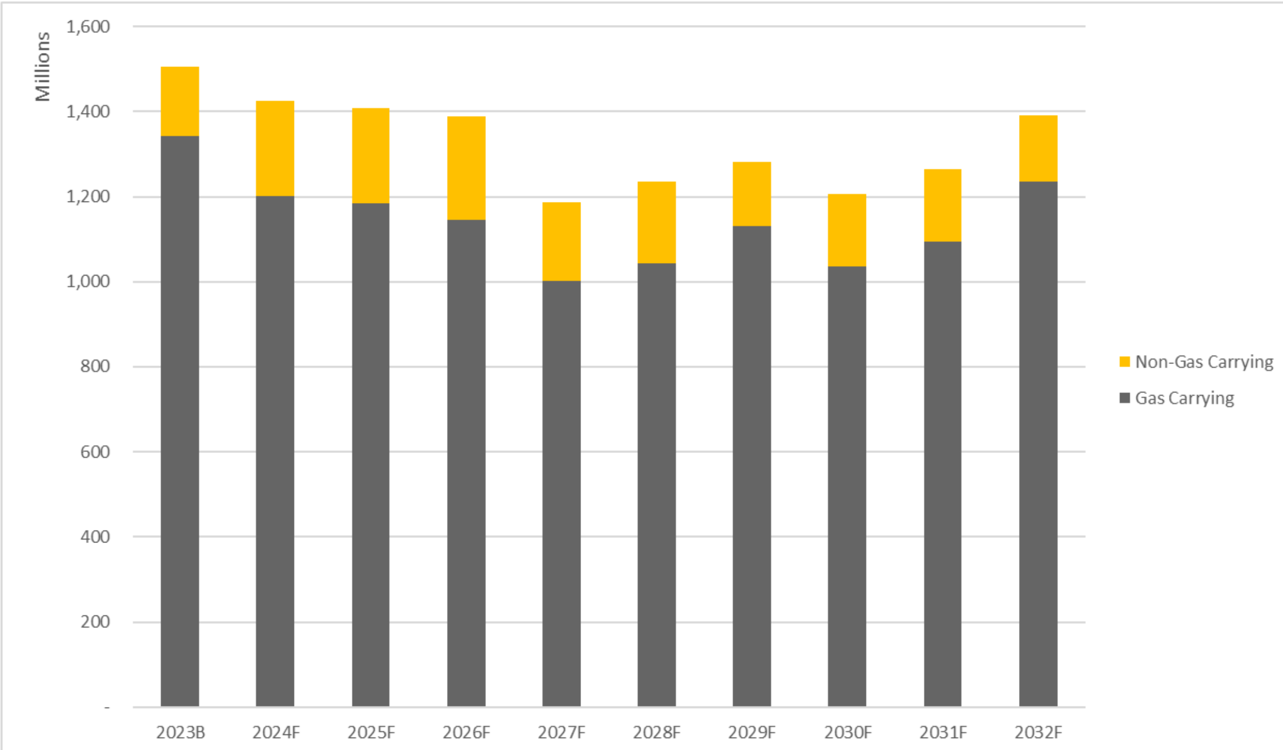


Figure 6.3-1: Gas Carrying vs. Non-Gas Carrying Categorization

There were 809 non-gas carrying investments within the 2023-2032 capital plan, none of the 809 investments were binary screened, as each fell within one of the following groupings that do not allow for IRP principles to be applied:

- Fleet & Equipment
- Real Estate and Workplace Services
- Technology and Information Services
- Extended Alliance
- Hydrogen investments
- Land/Structure investments in the Compression Stations and Transmission Pipe & Underground Storage asset classes have not been binary screened as they are focused on buildings, roadways and utilities or properties in proximity to other assets.

6.3.3 Binary Screening

Following **Section 6.3.2** above, EGI applied the binary screening to all remaining projects. This binary screening was completed in accordance with the criteria outlined in the OEB's IRP Decision (EB 2020-0091), and includes the following:

- **Timing:** If an identified system constraint/need must be met in under three years, an IRP Plan could not likely be implemented and its ability to resolve the identified system constraint could not be verified in time; therefore, an IRP evaluation is not required. Exceptions to this criterion could include consideration of supply-side IRPAs and bridging or market-based alternatives where such IRPAs can address a more imminent need.
  The timing criteria resulted in binary screen fails for projects within three years where supply-side alternatives were not viable. Investments within three years, where it was unclear if a supply side solution would be viable or not passed binary screening to allow for further assessment in the technical evaluation.

- **Customer-Specific Builds**: If an identified system need has been underpinned by a specific customer's (or group of customers') request for a facility project and either the choice to pay a Contribution in Aid of Construction (CIAC) or to contract for long-term firm services delivered by such facilities, then an IRP evaluation is not required.

This screening criteria did not result in the failing of any investments, as customer specific builds all appear to have rate impacts because they are not 100% covered by CIAC.

- **Community Expansion & Economic Development**: If a facility project has been driven by government legislation or policy with related funding explicitly aimed at delivering natural gas into communities, then an IRP evaluation is not required.
  Capital expenditures associated with Community Expansion projects and Economic Development projects are not included in the 2023-2032 AMP and, therefore, will not receive an IRP evaluation.

- **Pipeline Replacement and Relocation Projects**: If a facility project is being advanced for replacement or relocation of a pipeline and the cost is less than the minimum project cost that would necessitate a Leave to Construct approval, then an IRP evaluation is not required.
  The current LTC threshold was applied to the 2023-2032 capital plan and projects that fell under this threshold, in asset classes other than Growth System Reinforcement, failed the binary screening.

- **Emergent Safety Issues**: If an identified system constraint/need is determined to require a facility project for EGI to offer safe and reliable service or to meet an applicable law, an IRP evaluation is not required. An example of such a system constraint/need, and an emergent safety issue, would be if an existing pipeline sustained unanticipated damage and needed to be replaced as quickly as possible to ensure the safety of local communities and EGI broader transmission and distribution systems. Longer-term safety related system constraints/needs may be appropriate for an IRP Plan and should be considered on a case-by-case basis.
  This screening criteria caused a binary screen fail for investments that have been created for emergency replacements. Appendix B also includes program items, programs consist of multiple years of work that are forecast in one investment. Within programs, the specific investments are typically identified in the year of execution or when an emergency occurs. Investments within these programs may align with the emergent safety criteria, which was applied cautiously by EGI in response to the concerns in the IRP filing that this could be applied too broadly to the projects being assessed.

Applying the above criteria to the AMP in the binary screening step resulted in 886 projects passing the binary screening and 1392 failing. **Figure 6.3-2** provides the values associated with the binary screening results.

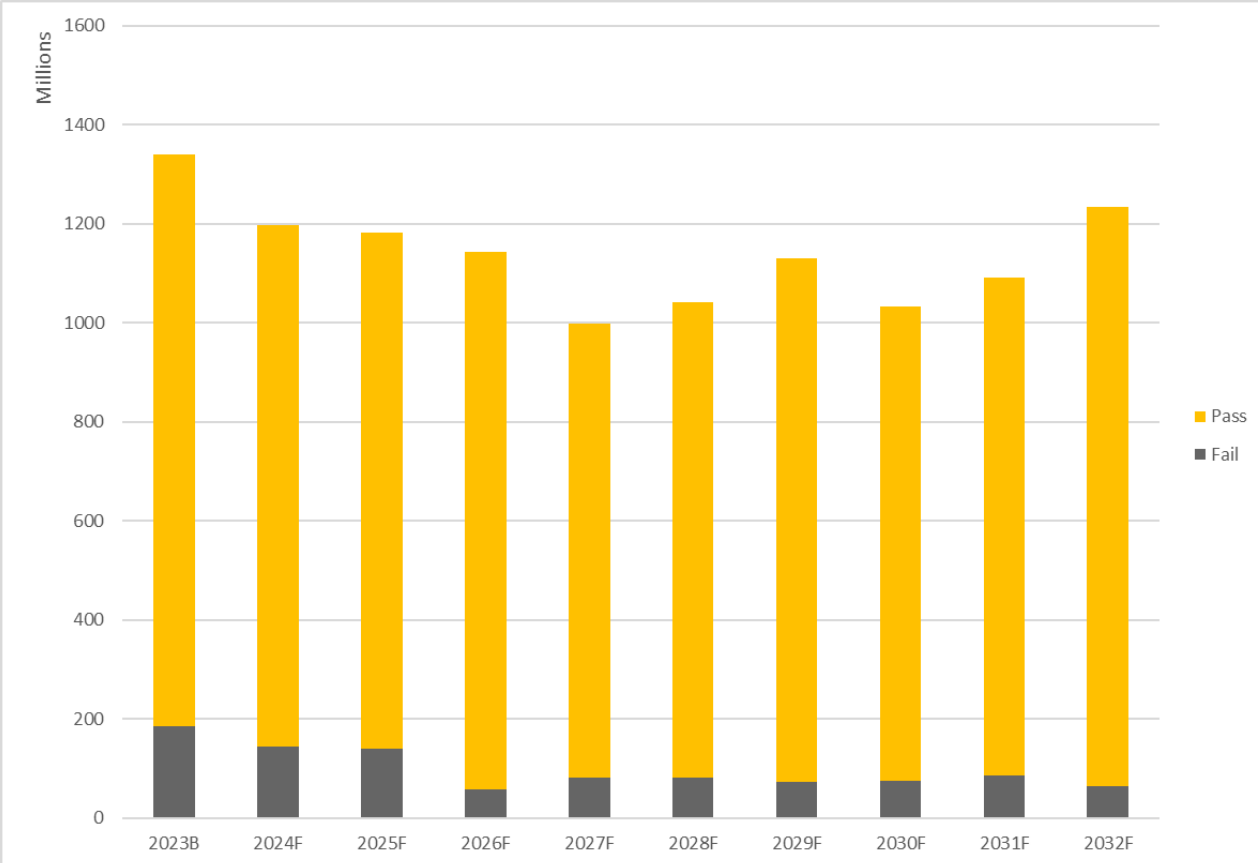


Figure 6.3-2: Binary Screening Results

Figure 6.3-3 provides a forecast breakdown of projects passing binary screening by asset program type. Transmission System Reinforcement and Distribution System Reinforcement have been shown individually as they largely represent growth opportunities. The "Other" category consists primarily of maintenance, replacement, and compliance driven activities.

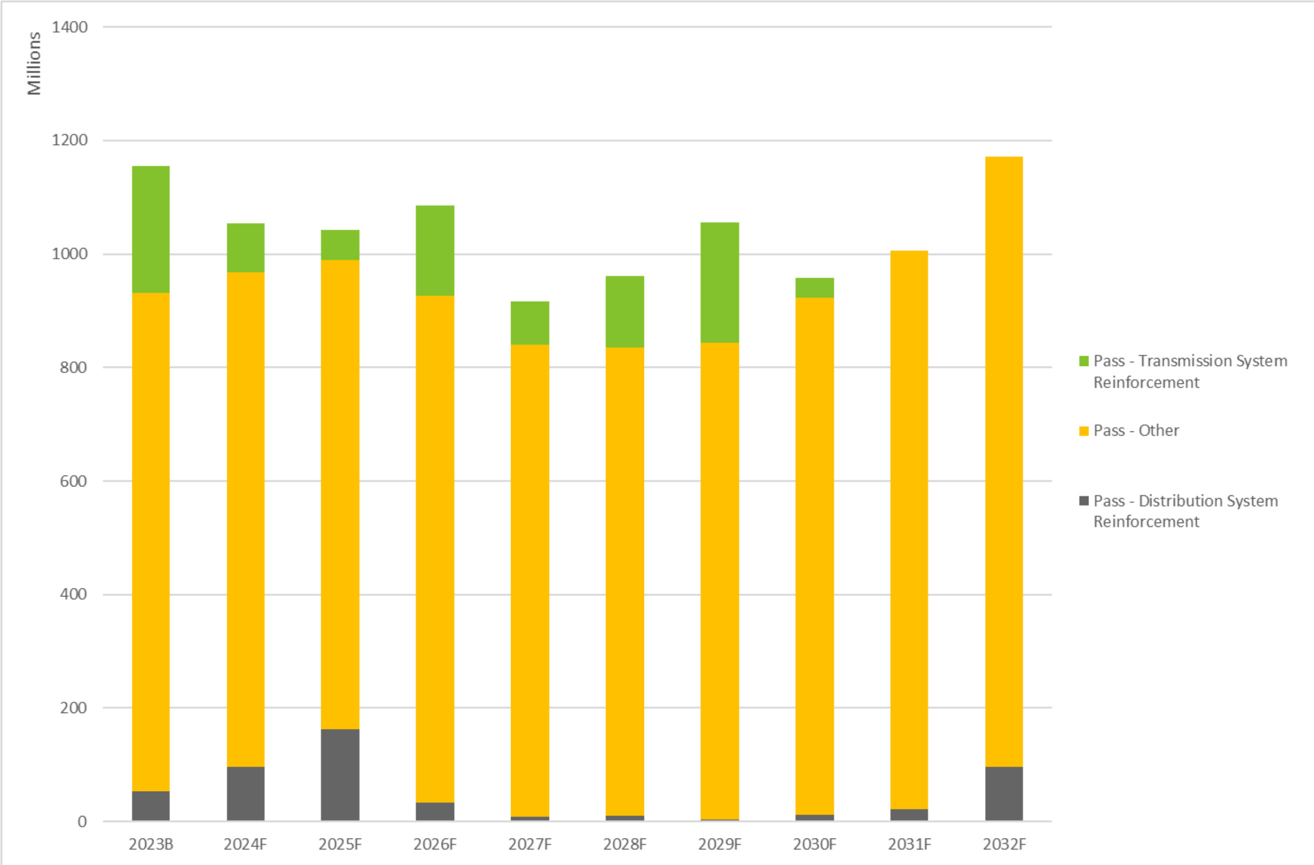


Figure 6.3-3: Binary Screening Pass by Asset Program

6.3.4 Technical Evaluation Project Review

Projects passing the binary screening are currently being reviewed in detail to verify that the forecast needs haven't changed, the project costs are sufficient, the project drivers haven't changed and to assess whether multiple projects can be addressed as part of the same IRPA Plan. To evaluate projects for IRPAs, both technically and economically, the identified needs and facility projects must be reviewed and updated where necessary. This project review step is time and resource intensive to complete, and, at the time of filing, is the step that EGI is actively engaged in. EGI is reviewing and assessing the following for each project:

- **Project Need:** The project need is reviewed to determine if any factors or forecasts have changed since the project was included in the 2023-2032 capital plan. Ensuring the facility project needs reflect the latest forecasts and information will allow for a more accurate comparison to IRPAs.
- **Project Cost:** Project costs are estimated when projects are identified for consideration in the 2023-2032 capital plan; however, since projects may be forecast up to ten years in advance, the cost estimates need to be reviewed and updated as required. Greater certainty of the project costs will provide a more accurate IRPA cost comparison.
- **Project Driver:** There are instances where one project is addressing more than one identified need (i.e., class location and growth). EGI will review the project drivers to ensure that the potential IRPAs will address multiple project needs, i.e., growth and risk/compliance needs.
- **Project Groupings:** EGI will review the 2023-2032 capital plan to group projects by system where applicable, as IRPAs may be more effective in addressing multiple needs in one area. This is very time-intensive to copy information from one system to another. EGI is exploring if these location details can be entered with project details in a manner that allows for future sorting, to ease the time required for this work.

It is critical that this technical evaluation project review take place on a project-by-project basis to ensure that the project is properly defined and that all possible alternatives are properly considered. Once the project details have been confirmed and updated as needed, the next step in the technical evaluation will commence This will mean that, in tandem, some projects will be moving through a detailed project review while others are having the next step of the technical evaluation completed. This will advance the work in the timeliest manner possible.

6.3.5 IRP Next Steps

At the time of filing the 2023-2032 AMP, EGI has completed the identification of constraints, and the binary screening for all of the projects. The current technical review focus is on both completing technical evaluation project reviews and then the assessment of what IRPAs are technically feasible for the investment. **Appendix B** contains the status of the fully complete technical evaluations to date. Of the investments that have had a technical review completed, the majority of them have failed at this stage. This is because it was found that these investments do not have any technically feasible IRPAs, even though they passed the binary screening stage. Examples of these investments include those addressing meters and regulators, AMP fittings, integrity digs etc.

The remaining Investments that are now moving through the technical evaluation, are those expected to most likely have a technically feasible IRPA; this is where the team is currently focused. Specifically, the focus is now on the following areas:

1) Investments with in-services dates of 2028 and prior, with the highest costs
2) Investments with in-services dates of 2028 and prior, in the geographic areas with the highest forecast growth

EGI will provide an updated version of Appendix B in 2023 to document the progress to date.

Investments that pass the technical evaluation will have an IRP scope developed and it will then move onto an economic evaluation. Both technical and economic evaluations are part of the two-stage evaluation process noted in the OEB's IRP Decision (EB-2020-0091). When an IRPA is determined to be the optimal alternative, the IRP Plan will be filed with the OEB for approval. Lastly, periodic review of any IRP Plans and system needs will occur as outlined in the OEB's IRP Decision (EB-2020-0091).

6.3.5.1 Economic Evaluations

At the time of filing the 2023-2032 AMP, EGI is still engaging in discussions with the IRP TWG to refine the use of the DCF+ test in the context of IRP. The group is looking to improve the test to better list and define the costs and benefits of facility alternatives and IRPAs and to clarify how these costs and benefits should be considered within the DCF+ test. Additionally, individuals focused on this aspect of the IRP process are looking to better understand how other jurisdictions are handling non-pipeline alternatives and understand how different techniques can be applied as part of EGI's evaluation.

As the DCF+ test is defined and EGI gains practice looking at investments through this lens, it is believed additional insight will be obtained to that can be applied to future DCF+ analysis.

6.3.5.2 Pilot Project Design, Economic Evaluation & Implementation

The pilot projects are expected to provide learnings and a better understanding of the impact of IRPAs on avoiding, deferring, or reducing facility projects They will also provide learnings on the DCF+ economic evaluation, IRPA program designs, implementation, and evaluation of IRPAs. The potential for scalability and transferability of the pilot learnings to other projects are a key consideration. In consultation with the IRP TWG, the two pilot options have been selected and the IRP team will work towards filing respective IRP Plans in the following months.

6.4 Assumptions

The 10-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 6.4-1: All Categories Assumptions

Assumption	Basis for Assumption
Optimization results are based on available information as of March 2022. *	Based on EGI's Optimize Portfolio of Solutions process, the portfolio of spend is determined through the completion of Copperleaf leveling and subsequent reviews. Results are based on best available information. *The timing of St. Laurent Ph 3 & 4 and Wilson Avenue Vintage Steel Replacement project (see Appendix A, Pg. 10, 13 and 14) was updated in May 2022 following LTC Decision (EB-2020-0293).
Future costs are valued at 2022 Present Value.	Current practice forecasts projects based on 2022 rates.
Future costs do not include inflationary measures.	Normal inflationary measures and impacts such as rising material costs, foreign exchange and labour are expected to be covered within investment contingency. Incremental shifts in inflation caused by global supply chain shortages, pandemics or other unusual circumstances have not been considered. A small number of programs with defined scope/unit rates have included a factor where information was available to inform the assumption (such as meter purchases and vehicle purchases).
All cost estimates are based on available information as of March 2022.	Using EGI's AIPM process, these requirements will be reviewed and revised as required.
All Risk Assessments are based on risk models and methodology as of March 2022.	Using EGI's Risk Management process, EGI's significant operational risks are reviewed quarterly 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.
The proposed capital expenditures represent facility alternatives.	As this is the first year that EGI has applied the IRP Framework to the AMP, EGI's IRP assessment process took place concurrently to the identification of the facility-based investments that underpin the AMP's 2023-2032 Capital Expenditures. Future iterations of the AMP will have proposed capital requirements that incorporate the comparison of viable facility and IRP alternatives to the extent possible prior to the next iteration of the AMP.

Table 6.4-2: 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. Renewal projects are planned to reduce this risk to the lowest practicable level.

Table 6.4-3: Customer Growth Assumptions

Assumption	Basis for Assumption
Customer growth is forecast using historical trends, and economic projections for the planning period.	The customer growth forecast considers projected housing starts, municipal growth forecasts, general economic indicators and projections, localized trends and macro-economic factors. EGI is cognizant that there may be impacts to customer growth forecasts based on climate/carbon policies.

Assumption	Basis for Assumption
Load forecasting is based on current understanding of temperature inputs described in Exhibit 3, Tab 2, Schedule 3 and estimated customer consumptions.	EGI has proposed a harmonized forecast methodology as part of this rebasing application. The estimated customer consumptions have historical Demand Side Management (DSM) built into the load forecast based on past results.

Table 6.4-4: Solution Planning Assumptions

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

7 Appendices

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Appendix A – Investments >$10M

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
100901	2023	10

Investment Name: Dawn to Corunna

Investment Description

Issue/Concern/Opportunity:

EGI recognizes its obligation to meet the firm demands of its customers; and as a result, assets are continually evaluated to identify hazards and to assess risks in order to ensure that they remain reliable, suitable, and fit for continued service. To this end, an Asset Health Review (AHR) was performed in 2018 and updated in 2021 as part of EGI's comprehensive Reliability, Availability and Maintainability (RAM) Study for the Corunna Compressor Station (CCS), which was completed by a consultant. The results of this study indicate that the health and maintainability of certain compressor units at the CCS are in decline. Reasons for this decline include, but are not limited to performance, functional issues with custom components (i.e., spare parts) and wear. As a result of these assessments, EGI has identified increasing obsolescence and reliability risks associated with certain CCS compressor units and is experiencing a need for increased maintenance and repair work to keep the units operational going forward.

Further, as a result of the compressor units' obsolescence and reliability issues, EGI has experienced continued and increasing compressor unit downtime and long lead repair time. This has created a need for increased maintenance and repair work performed by EGI personnel at the CCS. EGI has also undertaken comprehensive studies, including a site-wide quantitative risk assessment (QRA) to determine the severity of the increasing safety risks, and has determined that the current configuration of compressor units (which includes multiple compressor units in close proximity within a single building) results in an excessive level of process safety risk.

Assets: Compressors K701, K702, K703, K705, K706, K707 and K708

Related Investments: 734634 - Dawn to Corunna (Dawn Tie-in)

Recommended Alternative Description

Scope of Work:
The scope of the project includes the retirement and abandonment of 7 of the 11 existing reciprocating compressor units at the Corunna Compressor Station (CCS) and the construction of approximately 20 km of NPS 36 pipeline from the Dawn Operations Centre in the Township of Dawn Euphemia to the Corunna Compressor Station in St. Clair Township. The project will also include station work at the Dawn Operations Centre and the Corunna Compressor Station required to tie in the new pipeline.

Resources:
-Consultant resources for design
-Contractor resources for abandonment, construction and commissioning

Solution Impact:
This alternative provides a one-to-one replacement in design day storage system withdrawal capacity compared to the existing compressor units at the CCS facility that are proposed to be retired and abandoned. The NPS 36 pipeline will also provide equivalent storage injection capacity via existing compression units located within Dawn. Further, the proposed pipeline simplifies EGI storage operations by reducing the amount of rotating assets and running equipment. This opportunity to replace compression with a pipeline alternative also reduces emissions through utilization of existing hp compression at Dawn which have a lower burn rate (at higher efficiency).

Project Timing & Execution Risks:
-2021: File environmental assessment (EA) with Ontario Pipeline Coordination Committee (OPCC).
-2022: File Leave to Construct (LTC) with Ontario Energy Board (OEB).
This project will need two years of design procurement and construction and requires EA and regulatory approval. In-service date is slated for 2023.

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

Spend Profile

Name	Net Base Capex O (CA)
Dawn to Corunna	$ 147,778,280

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ 127,260,523	$ 5,009,329	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ 5,069,400	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

ENBRIDGE Investment Summary Report	Investment Code	Report Start Year	Number of Years
	100901	2023	10
	Investment Name		
	Dawn to Corunna		

Report Generation Date: 5/30/2022

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
48715	**2023**	**10**
Investment Name		
Dawn 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 & Execution Risk:
Regulatory approval and planning - 2 years, abandonment and remediation 18 months.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Compression Stations - Replacements
Investment Stage	Executing		

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	
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Spend Profile

Name	**Net Base Capex O (CA)**
Dawn C Compression Lifecycle	$ 125,000,000

Account Type	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Base CAPEX O	$ 200,000	$ 12,480,000	$ 24,960,000	$ 74,880,000	$ 12,480,000	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

ENBRIDGE Investment Summary Report	Investment Code	Report Start Year	Number of Years
	48715	2023	10
	Investment Name		
	Dawn C Compression Lifecycle		

Report Generation Date: 5/30/2022

ENBRIDGE Investment Summary Report	Investment Code: 734634	Report Start Year: 2023	Number of Years: 10
	Investment Name: Dawn to Corunna (Dawn Tie-in)		

Investment Description

Issue/Concern/Opportunity:
The Company recognizes its obligation to meet the firm demands of its customers; and as a result, assets are continually evaluated to identify hazards and to assess risks in order to ensure that they remain reliable, suitable, and fit for continued service. To this end, an Asset Health Review (AHR) was performed in 2018 and updated in 2021 as part of the Company's comprehensive Reliability, Availability and Maintainability (RAM) Study for the Corunna Compressor Station (CCS), which was completed by a consultant. The results of this study indicate that the health and maintainability of certain compressor units at the CCS are in decline. Reasons for this decline include, but are not limited to performance, functional issues with custom components (i.e., spare parts), and wear. As a result of these assessments, the Company has identified serious and increasing obsolescence and reliability risks associated with certain CCS compressor units and is experiencing a need for increased maintenance and repair work to keep the units operational going forward.
Further, as a result of the compressor units' obsolescence and reliability issues, the Company has experienced continued and increasing compressor unit downtime and long lead repair time. This has created a need for increased maintenance and repair work performed by EGI personnel at the CCS. EGI has also undertaken comprehensive studies, including a site-wide quantitative risk assessment (QRA) to determine the severity of the increasing safety risks, and has determined that the current configuration of compressor units (which includes multiple compressor units in close proximity within a single building), results in an excessive level of process safety risk.

Assets: Compressors K701, K702, K703, K705, K706, K707 and K708

Related Investments: 100901 - Dawn to Corunna

Recommended Alternative Description

Scope of Work:
This portion of the project is specific to the Union rate zone and the dismantlement of Tecumseh Measurement and tie-in to Dawn yard for the NPS 36 pipeline.

Overall Project Scope
The scope of the project includes the retirement and abandonment of 7 of the 11 existing reciprocating compressor units at the Corunna Compressor Station (CCS) and the construction of approximately 20 km of NPS 36 pipeline from the Dawn Operations Centre in the Township of Dawn Euphemia to the CCS in St. Clair Township. The project will also include station work at the Dawn Operations Centre and the CCS required to tie-in the new pipeline.

Resources:
•Consultant resources for design
•Contractor resources for abandonment, construction and commissioning

Solution Impact:
This alternative provides a one-to-one replacement in design day storage system withdrawal capacity compared to the existing compressor units at the CCS facility that are proposed to be retired and abandoned. The NPS 36 pipeline will also provide equivalent storage injection capacity via existing compression units located within Dawn. Further, the proposed pipeline simplifies EGI storage operations by reducing the amount of rotating assets and running equipment. This opportunity to replace compression with a pipeline alternative also reduces emissions through utilization of existing hp compression at Dawn which have a lower burn rate (at higher efficiency).

Project Timing & Execution Risks:
•2021: File environmental assessment (EA) with Ontario Pipeline Coordination Committee (OPCC).
•2022: File LTC with Ontario Energy Board (OEB).
This project requires two years of design procurement and construction and requires EA and regulatory approval. In-service date is slated for 2023.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Compression Stations - Replacements
Investment Stage	Executing		

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

Spend Profile

Name	Net Base Capex O (CA)
Dawn to Corunna (Dawn Tie-in)	$ 42,032,164

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ 38,446,515	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ 9,414,600	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

ENBRIDGE **Investment Summary Report**	Investment Code **734634**	Report Start Year **2023**	Number of Years **10**
	Investment Name		
	Dawn to Corunna (Dawn Tie-in)		
		Report Generation Date:	5/30/2022

ENBRIDGE	Investment Code 48732	Report Start Year 2023	Number of Years 10
	Investment Name		
Investment Summary Report	Waubuno Compression Lifecycle		

Investment Description

Issue/Concern/Opportunity:
The Waubuno compressor elevates available pipeline pressure to the Waubuno Pool Maximum Operating Pressure (MOP). Compression increases the working inventory value of the pool by approximately 3.5 PJ 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, at that time 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 usable 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 compressor out of service for at least one operational season.

Assets: Waubuno Compressor

Related Programs: N/A

Recommended Alternative Description

Scope of Work:
In order to meet lifecycle needs for the Waubuno storage facility, EGI is proposing to construct a new NPS 20 pipeline from Waubuno to TR-7 (~1.6 km). This will eliminate the requirement for a remote compressor at Waubuno; and therefore, this project will also involve the abandonment of the Waubuno Remote Compressor Unit and related equipment.
Waubuno Station Modifications (common in all scenario alternatives)
-New Control and Measurement Building
-Upgrade meters, control valve, and filter/separator
-Launcher and associated piping
Pipeline Construction
-NPS 20 Pipeline from Waubuno to TR-7/TR-2/TR-1
-~1.5 km NPS 20 Line (1,440 psi MOP)
-Connection to TR-7 (for injection); to TR-2 (200# Storage Suction); to TR-1 (Flexibility/Optionality)
-Valving to connect new pipeline with TR-1, TR-2, and TR-7 with overpressure protection
-Receiver and associated piping at new TR-7 valve site
-New Control Building

-Waubuno Compressor Abandonment (common in all alternative scenarios)
-Removal of the compressor and any associated equipment in compressor building.
-Removal of all the NPS 8 compressor suction and discharge piping back to their take-off at the bypass control valve.
-Removal of the aftercooler, filter and silencer.
-Removal of all electrical wiring, control wiring and SCADA communication wiring and panels associated with the compressor.
-Removal of the compressor building and foundation. As the site has been in existence since the 1980s, there is a strong possibility of ground contamination that will need remediation.
Resources:
-Consultant resources for design
-Contractor resources for abandonment, construction and commissioning
Solution Impact:
Replace approximately 3.5 PJ of inventory provided by the current compressor that is obsolete and poses the risk of significant downtime in the event of a failure.
Project Timing & Execution Risks:
-Requires Ontario Energy Board Leave to Construct approval
-Pool out of service
-Pipeline route not finalized
-Landowners may want abandoned pipeline removed
-Dependent on TR-7 pipeline
-2025 in-service date

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Compression Stations - Replacements
Investment Stage	Executing		

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

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
48732	2023	10

Investment Name

Waubuno Compression Lifecycle

Spend Profile

Name	Net Base Capex O (CA)
Waubuno Compression Lifecycle	$ 15,592,500

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ 252,000	$ 1,260,000	$ 14,017,500	$ 63,000	$ -	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ 630,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Report Generation Date: 5/30/2022

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
7660	**2023**	**10**

Investment Name: VPM - Erin Township

Investment Description

Issue/Concern:
It has been reported through a leak event that the vintage plastic pipe in Erin Township has experience cracking due to the stony soil in this area. The Gas Technology Institute (GTI) study on Aldyl A pipe has stated stress intensifier such as rock impingement could result in SCG in this type of plastic pipe.

Assets: Vintage plastic pipe in Erin Township

Related Programs: Pipe replacement vintage plastic

Recommended Alternative Description

Scope of Work:
Replace 2,700 metres of 4-inch PE main, 10,000 m of 2-inch PE main and 300 services.

Resources: Extended Alliance contractors

Solution Impact:
Mains Replacement Program will address leaks and condition issues as identified. The approach depends on the extent of the poor condition. Localized poor condition is managed through pipeline repairs whereas broader condition issues are managed through more extensive replacement.

Project Timing & Execution Risks: Cost estimates continue to be refined as project design progresses and approaches construction. The work might require temporary land rights acquisition and permitting ahead of execution, which could have an impact to the project schedule.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - DP - Main Replacement - General Mains Replacement
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	20 - Mississauga
	Asset Program (EGI)	DP - Main Replacement
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	Yes
	Compliance Justification & Code	Risk Assessment for Aldyl A attached
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

Spend Profile

Name	Net Base Capex O (CA)
VPM - Erin Township	$ 11,113,408

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ 2,366,350	$ 2,366,350	$ 2,197,800	$ 2,197,800	$ -	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ 709,905	$ 709,905	$ 709,905	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Report Generation Date: 5/30/2022

ENBRIDGE Investment Summary Report	Investment Code	Report Start Year	Number of Years
	100339	2023	10
	Investment Name		
	A10: Wilson Avenue, Toronto, VSM Replacement		

Investment Description

Issue/Concern/Opportunity:
Phased replacement of 12 gas main from Bathurst Ave. to Walsh Ave. Main is currently protected by Rectifier.
-The main on Wilson Ave. has numerous Pumpkins that have been installed on it. Starting from Wendell Ave. and going east towards Bathurst St.
-Corrosion on main has been an issue on Wilson Ave. due to stray current from Toronto Transit Commission (TTC) which continues to be an ongoing concern.
-The service connections have field-applied coatings which leaves a concern for future corrosion issues on this main.
-Regarding the main in the middle of the road on Wilson Ave., Curbside Valve Tee (CVT) repairs are problematic due to the location of the main.

Assets:
There is 8.5 km of NPS 12 HP Vintage Steel Main (VSM) installed between 1955 and 1964 on Wilson Ave. between Walsh Ave. and Bathurst St., Toronto.

Related Program: Not applicable.
Phased replacement of 12 Gas Main from Bathurst Ave. to Walsh Ave. Main is currently protected by Rectifier.
-The main on Wilson Ave. has numerous Pumpkins that have been installed on it. Starting from Wendell Ave. and going east towards Bathurst St.
-Corrosion on main has been an issue on Wilson Ave. due to stray current from Toronto Transit Commission (TTC) which continues to be an ongoing concern.
-The service connections have field-applied coatings which leaves a concern for future corrosion issues on this main.
-Regarding the main in the middle of the road on Wilson Ave. , Curbside Valve Tee (CVT) repairs are problematic due to the location of the main.

Assets:
There is 8.5 km of NPS 12 HP Vintage Steel Main (VSM) installed between 1955 and 1964 on Wilson Ave. between Walsh Ave. and Bathurst St., Toronto.

Related Program: N/A

Recommended Alternative Description

Scope: Replace approximately 8.5 km of 12-inch SC HP Vintage Steel Gas Main, like for like. There are approximately 384 services and 746 customers. In addition, install 2,000 m of NPS 2 PE IP and 400 m of NPS 4 PE IP, eliminating 136 HP services of the 384 existing HP services.

Resources: NPL to execute.

Solution Impact: Eliminate vintage steel main, reduce the number of HP services attached and reduce corrosion and coding deficiencies.

Project Timing & Execution Risks: 2024 to 2026
-Toronto and Region Conservation Authority (TRCA) permit is required.
-Moratorium - At Walsh Ave. W. past Matthews Gate, approximately 700 m expires December 31, 2024.
-Easement is required for the Humber River Crossing.
-Major Crossings - CP Rail, 400 Hwy, Humber River, Metrolinx – Barrie Line, the Allen, and 401 off ramp.

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

Spend Profile

Name	Net Base Capex O (CA)
A10: Wilson Avenue, Toronto, VSM Replacement	$ 72,015,518

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ -	$ 28,199,920	$ 41,647,950	$ 937,500	$ -	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ 1,447,500	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Report Generation Date: 5/30/2022

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
1938	2023	10

Investment Name: NPS 10 Glenridge Avenue, St. Catharines

Investment Description

Issue/Concern:
GENERAL CONCERNS: Vintage steel exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (Vintage Steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.

SITE SPECIFIC CONCERNS:
This project looks to replace approximately 8.7 km 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.

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 kilometers 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: Asset Renewal and Improvement Main Replacement - Replace approximately 7,500 m of vintage main NPS 10-inch ST IP and approximately 110 service connections with NPS 8 PE.

Resources: External Alliance contractors.

Solution Impact:
Main replacement project identified by Operations as high priority. Replacement is required due to age, pipeline condition and risk assessment results.

Project Timing & Execution Risks:
The timing for execution of this replacement project is planned for 2025/26.
Execution Risks: Moratoriums, third-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	Short 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

Spend Profile

Name	Net Base Capex O (CA)
NPS 10 Glenridge Avenue, St. Catharines	$ 11,804,455

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ -	$ 300,000	$ 6,047,929	$ 5,456,526	$ -	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ 3,565,604	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Report Generation Date: 5/30/2022

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
11443	2023	10

Investment Name

NPS 12 Martin Grove Rd Main Replacement: Lavington to St. Albans Rd.

Investment Description

Issue/Concern/Opportunity:

General Concerns:
Vintage steel exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (Vintage Steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.

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 cm, with 77 survey locations measuring less than 60 cm 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 Rd South to St. Albans Road.

Related Programs: 10086.

Recommended Alternative Description

Scope of Work: Replacement of approximately 6.4 km of NPS 12 steel main from Martin Grove Road and Lavington Drive South to Burnhmthorpe Rd, then west to Ashbourne Drive, then south to Auckland Road and St. Albans Road. Approximately 360 services are to be reconnected to a new IP PE sub-system.

Resources: 2026 Out to Construction Phase 2 and resources are to be determined.

Solution Impact: Main replacement project identified as high priority. Replacement is required due to age, pipeline condition and risk assessment results.

Project Timing & 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

Spend Profile

Name	Net Base Capex O (CA)
NPS 12 Martin Grove Rd Main Replacement: Lavington to St. Albans Rd.	$ 18,292,755

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ -	$ -	$ 400,000	$ 17,292,755	$ 600,000	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Report Generation Date: 5/30/2022

ENBRIDGE Investment Summary Report	Investment Code: 10293	Report Start Year: 2023	Number of Years: 10
	Investment Name: St. Laurent Phase 3 - North/South (NPS12/16 Steel)		

Investment Description

Issue/Concern/Opportunity:

General Concerns: Vintage steel exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (Vintage Steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.

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.

This project is to install 8,543 m of NPS 16/12 on Aviation Pkwy tying into the Network 6580 (Ottawa Gate) and running to Rockcliffe Station and abandon 12 km of NPS 12. Scheduled to be replaced 2024.

Full replacement of main comprising Network 6584 - The NPS 12 St. Laurent Ottawa North line is 13.3 km 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 Rd. (but does not include the crossing at the Rideau River to Station #61171A).

Assets: Approximately 2.4 km of NPS 16 ST and 6.9 km of NPS 12 ST to be installed and rebuild 3 stations (Rockcliffe, Birch and St. Laurent Control)

Related Programs: 10089, 10288, 10290, 10291, 10292, 10289, 10294.

Recommended Alternative Description

Scope of Work: Install 6.5 km NPS 12 Steel Gas Main; Install 2.4 km NPS 16 Steel Gas Main; Install 5.1 km Plastic Gas Main and relay all XHP services to the new plastic gas main.

In 2024, for the Plastic Gas Main scope, approximately 3 km will be installed on St Laurent Blvd and Sandridge Road and 2.1 km on Coventry Rd. / Ogilvie Rd. and St. Laurent Blvd. Also, for the Steel Gas Main, approximately 6.5 km of NPS 12 will be installed on Cummings Ave., Brittany Drive., St. Laurent Blvd and Sandridge Road, and 2.4 km of NPS 16 on Michael Street.

Resources: TBD

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.

Timing & Execution Risks: Phase 3 is to executed in 2024, but the NPS 16/12 cannot be abandoned until this main is installed and all the services have been transferred onto the new plastic gas main.

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

Spend Profile

Name	Net Base Capex O (CA)
St. Laurent Phase 3 - North/South (NPS12/16 Steel)	$ 54,437,118

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ 1,000,000	$ 43,799,598	$ 1,550,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ 5,000,000	$ 1,000,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Report Generation Date: 5/30/2022

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
10294	**2023**	**10**
Investment Name		
St. Laurent Phase 4 - East/West (NPS12 Steel)		

Investment Description

Issue/Concern/Opportunity:

General Concerns:
Vintage steel exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (Vintage Steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization

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 km 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 Rd. (but does not include the crossing at the Rideau River to Station #61171A).

In 2018, pressure increased to Avenue O.

In 2019, approximately 3.1 km of plastic will be installed on Tremblay and the Avenues, and the services transferred over to intermediate pressure (IP). Also, due to a road moratorium, 2 km of 6-inch PE IP main on St. Laurent between Donald St., and Montreal needs to be brought forward from 2021 to 2019 and approximately 80 services.

Assets: Phase 4 - This project is to install 3,685 m of NPS 12 in 2022 and relay 1 service.

Related Programs: 10089, 10288, 10290, 10291, 10292, 10293, and 10289.

Recommended Alternative Description

Scope of Work: Install 3.1 km NPS 12 Steel Gas Main; Install 3.2 km Plastic Gas Main and relay all XHP services to the new plastic gas main.

In 2025, approximately 3.2 km of plastic will be installed on Industrial Ave., St. Laurent Blvd and Lancaster Road and all the XHP services will be transferred over to intermediate pressure (IP). Also, approximately 3.1 km of steel will be installed on Ogilvie Road & Coventry Road and all existing vintage steel pipeline will be abandoned once the new pipeline is energized.

Resources: To be determined

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.

Timing & Execution Risks: Phase 4 is to be executed in 2025 but the NPS 16/12 vintage steel pipeline cannot be abandoned until this main is installed and all the services have been transferred onto the new intermediate pressure 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

Spend Profile

Name	Net Base Capex O (CA)
St. Laurent Phase 4 - East/West (NPS12 Steel)	$ 19,141,532

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ -	$ -	$ 18,224,123	$ 530,000	$ -	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ 638,911	$ 879,637	$ -	$ -	$ -	$ -	$ -	$ -

Report Generation Date: 5/30/2022

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
503350	2023	10

Investment Name: Moulton Replacement BU

Investment Description

Issue/Concern/Opportunity:
There is 5.6 km of NPS 8 Intermediate Pressure (IP) bare steel main to be replaced with NPS 8 IP YJ steel main between #1472 Hwy 3 to #2199 Hwy 3. The in-service date is 2025.
Justification: Replacement of NPS 8 IP bare steel with size-on-size NPS 8 IP YJ steel main for the 5.6 km segment.

Assets: NPS 8 IP gas main between #1472 Hwy 3 to #2199 Hwy 3.

Related Program: N/A

Recommended Alternative Description

Scope of Work: Due to the existing NPS 8 IP steel gas main being bare pipe, the project scope includes replacement of this line with NPS 8 YJ steel gas main.

Resources: Extended Alliance Partners.

Solution Impact: Replacement with NPS 8 YJ steel gas main will remove the unprotected NPS 8 bare steel pipe for 5.6 km.

Project Timing & Execution Risk: Construction planned for 2025.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - DP - Main Replacement - Bare & Unprotected Steel Replacement Program
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_16 - Hamilton
	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

Spend Profile

Name	Net Base Capex O (CA)
Moulton Replacement BU	$ 14,452,000

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ -	$ 600,000	$ 13,752,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Report Generation Date: 5/30/2022

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
100295	2023	10

Investment Name

Div_04: NPS 8 Port Stanley, London, Replacement

Investment Description

Issue/Concern/Opportunity:
The NPS 8 Port Stanley line is approximately 20 km of NPS 8 built in 1959, with unknown grade and wall thickness, bare and protected, and 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 m 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. In 2000, 6.8 km of main were replaced due to corrosion and exposed pipe. In 2003, 230 m were replaced 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: Port Stanley line is approximately 20 km of NPS 8 built in 1959.

Related Programs: N/A

Recommended Alternative Description

Scope of Work: The 6.8km of existing NPS 8 section which was recently replaced in year 2000 is not in scope. Approximately 14km of existing NPS 8 steel main will be replaced. Starting from both ends of the year 2000 installed NPS 8 section, 2.1km of NPS 6 (resized down from NPS 8) steel main will be installed headed north to Middlemarch and 2.8km of NPS 6 (resized down from NPS 8) will be installed headed south to the Port Stanley gate station. Furthermore, 4.5km of NPS 8 will be installed from Middlemarch North to the existing NPS 10 tie-in on Talbot line and 4.5km of NPS 8 will be installed from Middlemarch headed east to the St. Thomas South 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: TBD

Projects Timing and Risks: 2024 Execution

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - DP - Main Replacement - Vintage Steel Mains Replacement Program
Investment Stage	Executing		

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	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Spend Profile

Name	Net Base Capex O (CA)
Div_04: NPS 8 Port Stanley, London, Replacement	$ 15,221,497

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ 489,630	$ 14,401,776	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Report Generation Date: 5/30/2022

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
736530	**2023**	**10**

Investment Name: Sudbury Lateral Integrity Digs 2023

Investment Description

Issue/Concern/Opportunity:

General: The Integrity Digs portion of the Integrity Management Program is to specifically capture integrity dig work to respond to inspections. 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 the pipeline systems 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 inline 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 that are identified through the inspections.

Project-Specific: The pipeline section was in-line-inspected in 2021 with several Phase 2 features (corrosion with metal loss, and dents, etc.) reported. In compliance with the TIMP condition monitoring standard, all Phase 2 features are required to be investigated and repaired within 12 months of discovery. Consequently, 67 digs have been planned for the 2023 integrity dig works to effect repair or replacement of affected sections.

Assets: NPS 10 x 121 km Sudbury Lateral Section 1

Related Programs: 48268, 734703, 48244, and 736531.

Recommended Alternative Description

Scope of Work: Phase 1 (immediate response) anomalies detected from the 2021 in-line inspection (ILI) report will be mitigated through integrity verification digs and subsequent repair or replacement of affected sections.
Project-Specific: 67 digs to be executed on the NPS10 Sudbury Lateral Section 1.

Resources: TBD

Solution Impact: By mitigating all (immediate response) anomalies, the Integrity Management Program reduces the probability of pipeline failures, consequently reducing the overall risk to the public and ensuring reliable gas supply.

Project Timing & Execution Risks: 67 Integrity digs are to be executed in 2023. Dig permit constraints may limit the total number of digs executable in 2023.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - DP - Integrity - Integrity Digs
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)	DP - Integrity
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	Yes
	Compliance Justification & Code	The Integrity Digs portion of the Integrity Management Program is to specifically capture integrity dig work to respond to inspections. 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

Spend Profile

Name	Net Base Capex O (CA)
Sudbury Lateral Integrity Digs 2023	$ 10,000,000

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ 10,000,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Report Generation Date: 5/30/2022

ENBRIDGE Investment Summary Report	Investment Code	Report Start Year	Number of Years
	3610	2023	10
	Investment Name		
	CROWLAND STORAGE TRANSFER		

Investment Description

Issue/Concern/Opportunity:
Crowland Storage Transfer Station is located on EGI-owned property of approximately 7,300 m2 fenced compound in the Port Colborne, Ontario, approximately 7 km southeast of Welland, Ontario, within a rural area, in close proximity to a railway corridor. This station accepts natural gas from EGI Crowland Gas Storage facilities and provides supply to and from XHP networks, through components within the measurement system, pressure control system , heating system, odourant system, and telemetry system. This station delivers and withdraws natural gas from Storage Operations Wells in the Niagara Region. The following issues have been identified at this station:

Odourization: The odourant system was installed in 2000. The current configuration of the odourant system does not ensure adequate containment of the odourant product in the event of a leak and does not meet the current engineering standards and approvals.
Telemetry & Electrical: The existing electrical system does not meet current EGI electrical installation standards. This poses a potential electrical hazard and faulty wiring may result in lost communications.
Compliance: The Canadian Electrical Code Section 22.1 indicates that all electrical and instrumentation equipment located in a hazardous area must be rated for that area classification. The Remoter Terminal Unit (RTU) building has been identified as being located in an area classification and its equipment is not rated to operate in this environment. This is a risk of ignition and fire in the event of a gas leak.

Phase Cost Estimate Includes:
1) Install annubars on inlet and outlet.
-Install actuator on each operator regulator and on valves 8, 9 and 10.
Required electrical work:
-Relocate RTU building out of classified area (including new building and foundation).
-Install generator and automatic transfer switch.
-Upgrade tower to improve signal quality.
-Upgrade lighting.
2) Install filter separator and receiver on inlet.
-Install moisture analyzer and gas chromatograph.
-Install new YZ odourant system (including new building and foundation).
-Include station bypass equipment and setup (assume bypass of the whole station is needed to complete the work). Includes retrofits to station piping for temporary station connection.
-Includes all planning/design costs including drafting, surveys and permits, and geotechnical study.

Assets: Crowland Station

Related Programs: Major work is scheduled to take place to upgrade the EGI Storage facilities at Crowland. This project would be linked and completed in conjunction with that Storage upgrade #6377

Recommended Alternative Description

Scope Work:
Filtration: Add filter/separator on station inlet
Pipes & Valves: Replace station inlet and outlet valves and associated piping. Existing bypass valve will be upgraded to a 2 valve configuration (plug and ball).
Heating System: Design team will determine if required.
Pressure Control: Sizing will be confirmed during design.
Odourant System: Will be upgraded with secondary containment for the odourant injection pumps to meet current design standards.
Telemetry & Electrical: Upgrade electrical and add pressure transmitters as required. Add remote actuation to valves to allow for efficient use of the STO/Distribution Stations facilities. Add gas chromatograph and moister analyzer.
Measurement: Ultrasonic meter on outlet of the Port Colborne line
Compliance & Others: The existing RTU building will be relocated to an area outside of any hazardous areas.

Solution Impact: TBD

Resources: Company Crews, Contractor Labour and 3rd Party vendor suppliers

Project Timing & Execution Risk: Planning in Year 1, Execution in Year 2 / 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)	80 - Niagara
	Asset Program (EGI)	DS - Gate, Feeder & A Stations
	Asset Class (EGI)	Distribution Stations
2. Compliance	Compliance Investment	Yes
	Compliance Justification & Code	RTU building location contravenes Canadian Electrical Code Section 22.1 for unrated equipment operating in a hazardous area classification.
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

Spend Profile

Name	Net Base Capex O (CA)
CROWLAND STORAGE TRANSFER	$ 19,335,824

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ 18,905,824	$ 430,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

ENBRIDGE Investment Summary Report	Investment Code	Report Start Year	Number of Years
	3610	2023	10
	Investment Name		
	CROWLAND STORAGE TRANSFER		

Report Generation Date: 5/30/2022

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
735335	**2023**	**10**

Investment Name

GTAW Parkway Gate Station Rebuild Phase 2

Investment Description

Project: Parkway East Phase 2. Phase 1 commenced in 2021.

Issue/Concern/Opportunity: The following sub-assets will be rebuilt due to the issues described below:

Regulators: Two existing Becker control valves, i.e., NPS-8 and NPS-6 downstream operators – PRV-0502 and PRV-0504, Runs 9 and 10 on TC Energy feed (quantity is two) are defective and will not lock up; therefore, replacement is required. Currently, the inlet valve from the TC Energy feed is used to completely shut off the TC Energy feed; otherwise, the control valves will bleed by and affect nominations in the summer, automated TC Energy inlet valve for emergency shutoff from TC Energy, as well as to ensure inlet valve is closed to avoid bleed by of Becker control valves in summer conditions (CLOSE ONLY VALVE). Flow control valves on the TC Energy feed are Fairchild's (will replace with DNGPs – RUNS 9/10) not a computer-controlled regulator and do not sense downstream pressure. Isolation valves for each run are operational. DNGP should also replace Fairchild for 12-inch Union East – CV replacement (12-inch closest to Boiler building - RUN 1); 4th Fairchild is on the MSL – not required – disconnect and replace with VRP pilot (pressure control only due to downstream system operation). The station can be down to facilitate work as system can be fed from Parkway West. An additional five Jordan motors that are obsolete are to be replaced with Rotork motors (quantity is five). Due to capacity constraints and designing for future flow provided by Distribution Optimization Engineering (DOE) / TSP, Run 1 T4 Becker is to be replaced with T1 Becker (NPS 12). Run 3 has undersized isolation valves (currently NPS 8) and will need upsizing to NPS 16.

Civil: There is no urethane layer between the pipe support cradle and the bottom of the pipe. A single new Odourant building is required. The wall between the Pressure Transmitter and Remote Terminal Unit (RTU) room is to be opened up for entire building to be RTU room. Demolition of existing Generator building is required. The Storage building is to be removed due to end of life.

Piping & Valves: An increase in pipe size near heaters to NPS 30 along with inlet/outlet HX valves to ensure flow requirements can be achieved. Upsizing downstream header and inlet pipe to regulators to NPS 30 is required to ensure it can handle capacity requirements.

Odourant: The Odourant system is a metallic odourant building without adequate containment with a rusted containment pan. The fill connection is outdoors. Supports are not fire-rated and no Fire Suppression system is installed. Grating within the building is not safe for accessing valves and equipment. A new Odourant building is required. Two 5,000 GAL odourant tanks complete with electric pumps are to be installed. Low-flow and high-flow pumps with full redundancy on winter pumps on each outlet are required. Switchover between pumps should be automated.

Telemetry & Electrical: Existing obsolete Bristol 3330 is to be replaced with Control Wave Micro. Additional electrical wiring and cabling (including power distribution) and programming are to be included in scope.

Assets: Station components are to be replaced as described above in Phase 2.

Related Program: Not applicable.

Recommended Alternative Description

Scope of Work:
Phase 2 of the station rebuild to address the issues described below related to pressure control issues, odourant compliance issues, Remote Terminal Unit (RTU) / Telemetry upgrades from obsolete equipment.

Resources:
This work will be performed by internal and contractor construction crews.

Solution Impact:
Rebuilding the station components will mitigate the safety risks to employees, contractors, and the general public.

Project Timing & Execution Risks:
This is Phase 2 that will commence in 2022 and will continue through 2023 with some assets being planned to be in service in 2022 and the balance in 2023.

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	New odorant system including odorant tanks required to meet 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)	Yes

Spend Profile

Name	Net Base Capex O (CA)
GTAW Parkway Gate Station Rebuild Phase 2	$ 12,300,000

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ 8,500,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ 400,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Report Generation Date: 5/30/2022

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
503369	2023	10

Investment Name

Lisgar Station

Investment Description

Issue/Concern/Opportunity:
The Lisgar Gate Station is located at a highly populated area in the City of Mississauga. The station is situated in an urban setting and is surrounded by residential buildings, a commercial plaza, and a church. The station has multiple feeds (two transmission lines and one XHP CER line) and various outlets to the local distribution networks. In the event of a major incident, the consequence would be significant given the close proximity of the houses and buildings.

Justification: The following issues and deficiencies have been identified:
- Pipes & Valves have been deemed unreliable at this site and requires removal and installation of new pipes, fittings, and valves.
- Heating system has been deemed unreliable as it has reached its end-of-life cycle usage. The placement of the heat exchangers in the basement of the boiler building has caused maintenance roadblocks along with flooding concerns.
- Pressure regulation: 20002A regulation has been deemed unreliable, regulation will be rebuilt because of inconsistent flows through them. 20002D has suffered from frost heaving issues as well and requires a rebuild.
- Odorant system current configuration does not ensure adequate containment of the odorant product in the event of a leak and does not meet the current engineering standards and approvals. The pumps need automation along with redundancy for better operational efficiency.
- Regulator building that houses 20002B & 20002C needs a noise evaluation study to determine a better noise attenuation solution.
- Existing Measurement is not reliable and accurate. A more robust and accurate measurement needs to be installed for custody transfer purposes

Assets: Distribution Station Assets at the Lisgar Gate Station

Related Program: AFF - 219 - NPS 24 Lisgar to Pine Valley - permanent launcher support (23192)

Recommended Alternative Description

Scope of Work: Rebuild the station with the following scope:
- Pipes & Valves: Replace station isolation valves with new ball valves. All station piping and valves will be examined to ensure that material specifications and their current condition are acceptable for continued use. Projected future station capacity requirements will also be considered.
- Heating System: Replace the boilers and heat exchanger. Boiler piping will also have to be replaced to match up with the new boilers and heat exchanger. Heat exchangers will need to be replaced and installed outside of the building.
- Pressure Control: There are three different stations at Lisgar. Each will be evaluated for current flow requirements through the design stage.
- Odorant System: The new odorant building will be installed that will include sufficient secondary containment which is not part of the current design. A new odorant tank will also be required, along with a second backup pump injection system to serve as redundancy.
- Telemetry & Electrical: The existing RTU cabinet and panel will be replaced with a new 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 upgrades, modem and firewall upgrades, station lighting upgrades, weather station installation/replacement.
- Measurement: Four new measurement ultrasonic flowmeters will be installed on the inlet NPS 30 from the new Union Gas takeoff. Another measurement will be installed at the outlet on the NPS 24 CER line. Piping will be designed to ensure gas measurement when operationally flowing from the NPS 24CER line to the NPS 20 and reverse. The flow meters will be programmed to have automatic run switching depending on the demand. The NPS 30,20 and 16 outlets will also be equipped with annubar flow meters to capture individual flowrates leaving the station.
- Compliance & Others: Sump pumps will be replaced/relocated to remove them from the confined space.

Resources: Capital Development and Delivery

Solution Impact: Risk reduction to the existing Lisgar Station site by replacing obsolete equipment.

Project Timing & Execution Risks: 2023/2024 Execution

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	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

Spend Profile

Name	Net Base Capex O (CA)
Lisgar Station	$ 18,414,114

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ 15,390,204	$ 1,823,940	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ 1,273,400	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Report Generation Date: 5/30/2022

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
1024	**2023**	**10**

Investment Name

NW 6581 Ottawa Reinforcement Phase 2 SRP

Investment Description

Issue/Concern/Opportunity: 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 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 were approximately 193,553 customers on the associated networks as of 2016.

Assets: Existing NPS 12 HP Pipe

Related Program: Not applicable

Recommended Alternative Description

Scope of Work: The proposed scope includes the installation of 7 km of NPS 12 high pressure main from Greenbank Rd. and W Hunt Club Rd. to Princess of Wales Dr. and W Hunt Club Rd. along W Hunt Club Rd.

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 & Execution Risks: The Project is proposed to start in 2030 and be completed by 2032.

Risks: Weather impacts, resource availability, and 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	
	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

Spend Profile

Name	Net Base Capex O (CA)
NW 6581 Ottawa Reinforcement Phase 2 SRP	$ 52,686,000

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 268,000	$ 5,348,000	$ 47,070,000
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Report Generation Date: 5/30/2022

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
736259	2023	10

Investment Name: Hamilton Industrial Reinforcement

Investment Description

Issue/Concern/Opportunity:
Reinforcement required to support changes to industrial demand in the area.

Assets: Distribution Reinforcement

Related Program: N/A

Recommended Alternative Description

Scope of Work: Route options are currently being assessed for constructability. Routes range from NPS 10 to NPS 30.

Resources: Capital Development, Business Development, Engineering Construction

Solution Impact: In May 2021, the customer initiated a significant growth project with Enbridge for an increased demand of 96,000 m3/hr.

Project Timing & Execution Risk: November 2025 as required by the customer.

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_16 - Hamilton
	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

Spend Profile

Name	Net Base Capex O (CA)
Hamilton Industrial Reinforcement	$ 103,000,000

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ 2,000,000	$ 8,000,000	$ 88,000,000	$ 5,000,000	$ -	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Report Generation Date: 5/30/2022

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
100703	**2023**	**10**

Investment Name: SRP_LUG East_Kingston_Creekford Rd_Reinforcement_NPS8_6200m_6895kPa

Investment Description

Issue/Concern/Opportunity: Kingston lateral replacement to be completed from Westbrook CMS to Woodbine TBS to account for forecasted growth, and to address Class Location and depth of cover issues which exist on the current Kingston lateral.

Assets: Kingston Lateral Replacement

Related Program: N/A

Recommended Alternative Description

Scope of Work: The project will replace the existing NPS 6 ST 6895 kPa distribution pipeline from the Westbrook TCPL takeoff to the Woodbine Town Border Station with an NPS 8 ST 6895 kPa pipeline. This project supports all pressures downstream to Kingston. The project is required to support growth and address additional other depth of cover, station and class location issues.

Resources: Company crews, 3rd party contractor crews and 3rd party vendors.

Solution Impact: Organic growth on the Kingston system wide. This reinforcement supports the entire system and downstream networks.

Project Timing & Execution Risks: System reinforcement is required in 2024 as per current plan and significant growth on systems. Risks include weather, resource availability, procurement of materials, 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_22 - Kingston
	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

Spend Profile

Name	**Net Base Capex O (CA)**
SRP_LUG East_Kingston_Creekford Rd_Reinforcement_NPS8_6200m_6895kPa	$ 24,321,527

Account Type	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Base CAPEX O	$ 3,700,000	$ 18,800,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended

Report Generation Date: 5/30/2022

ENBRIDGE **Investment Summary Report**	Investment Code **30523**	Report Start Year **2023**	Number of Years **10**
	Investment Name		
	SRP_North_Parry Sound_Seguin Trail_Reinforcement_NPS6_8500m_4960kPa		

Investment Description

Risk/Concern/Opportunity: This project was generated as part of Distribution Optimization Engineering's 2021 System Reinforcement Plan (SRP). 8.5 km of NPS 6 steel looping is required on the existing Parry Sound Lateral (4960 kPa) to maintain the minimum inlet into the Parry Sound TBS station (44801002) and support the forecasted growth in Parry Sound. Without this project, the forecasted growth on the system would increase the likelihood that inlet pressures at Parry Sound TBS would drop below minimum operating limits.

Assets: The existing NPS 4 (4960 kPa) Parry Sound Lateral will be impacted by this investment.

Related Program: N/A

Recommended Alternative Description

Scope of Work: Loop the existing NPS 4 (4960kPa MOP) pipe with NPS 6 for 8.5 km.

Resources: This work will be performed by internal and contractor operations crews.

Solution Impact: The 8.5 km of NPS 6 steel main will ensure forecasted demands (based on the econometric forecast) for the Parry Sound distribution system are met (out to 2042).

Project Timing & Execution Risks: The expected in-service date for the proposed looping is 2032.

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_43 - Sudbury & S.S. Marie
	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

Spend Profile

Name	Net Base Capex O (CA)
SRP_North_Parry Sound_Seguin Trail_Reinforcement_NPS6_8500m_4960kPa	$ 17,500,000

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 17,500,000
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Report Generation Date: 5/30/2022

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
30542	2023	10

Investment Name

SRP_Southeast_Owen Sound_County Rd 40_Reinforcement_NPS12_11800m_4670kPa

Investment Description

Risk/Concern/Opportunity: The Owen Sound system north of St. Jacob's historically adds about 1300 customers per year and growth has been strong along the lakeshore (Port Elgin, Southampton, Owen Sound & towards Collingwood).

Assets: Distribution Reinforcement

Related Programs: N/A

Recommended Alternative Description

Scope of Work: The project will loop the existing NPS10 ST 4,670 kPa main from existing PH4 reinforcement to Squire, Ontario with NPS12 ST main, as well as install a valve site and 12-inch receiver facilities. Alternative running lines and pipe sizes can be determined closer to the project design stages in 2023 and 2024. This project supports all pressures downstream to Owen Sound, Port Elgin, Southampton, Wiarton, Sauble Beach and east of Owen Sound. Actual growth rates and loads will need to be confirmed closer to the project planning stages.

Resources: Company crews, third-party contractor crews and third-party vendors.

Solution Impact: Organic growth on the Owen Sound system wide north of St. Jacobs Transmission Station. This reinforcement supports the entire system and downstream networks.

Project Timing & Execution Risks: System reinforcement is required in 2025 as per current plan and significant growth on systems. Risks include weather, resource availability, and procurement of materials, 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_07 - Waterloo
	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

Spend Profile

Name	Net Base Capex O (CA)
SRP_Southeast_Owen Sound_County Rd 40_Reinforcement_NPS12_11800m_4670kPa	$ 26,400,000

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ -	$ -	$ 26,400,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Report Generation Date: 5/30/2022

ENBRIDGE Investment Summary Report	Investment Code	Report Start Year	Number of Years
	736075	2023	10
	Investment Name		
	WIND: Wheatley-1B - Panhandle Distribution Reinforcement - Wheatley Lateral Replacement and Reinforcement		

Investment Description

Risk/Concern/Opportunity:
Greenhouse growth in the Windsor area continues. The Panhandle distribution network needs to be reinforced to allow for the continued industrial customer expansion. A Panhandle transmission reinforcement is also required to meet the demand of the region.

Assets: Distribution Reinforcement

Related Programs: N/A

Recommended Alternative Description

Scope of Work: Wheatley-1B is a distribution system looping project which requires a new station at Wheatley Rd. and Goodreau Line: 5,300 m of NPS 8 and 10,800 m of NPS 8.

Resources: This work will be performed by internal and contractor construction crews.

Solution Impact: New facilities in this area will provide the reinforcement required to support the greenhouse industry growth.

Project Timing & Execution Risks: Project timing will have to align with the ability to justify natural gas expansion (commercial certainty of the new customers). Depending on the geographical spread of industrial customer expansion, the scope of the project will need to be adjusted to support the forecasted need.

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_01 - Windsor
	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

Spend Profile

Name	Net Base Capex O (CA)
WIND: Wheatley-1B - Panhandle Distribution Reinforcement - Wheatley Lateral Replacement and Reinforcement	$ 16,500,000

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ 935,000	$ 15,560,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Report Generation Date: 5/30/2022

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
736975	2023	10

Investment Name: Enbridge Gas Distribution System Hydrogen Feasibility Study

Investment Description

Risk/Concern/Opportunity:
Comprehensive techno-economic feasibility study of blending hydrogen into Enbridge Gas Inc.'s (EGI) existing natural gas distribution and transmission network across Ontario.

Assets: Hydrogen Study

Related Programs: N/A

Recommended Alternative Description

Scope of Work:
Evaluate the technical feasibility and maximum limits of blended hydrogen gas in existing networks, identify necessary retrofits or upgrades for varying concentrations of hydrogen, and develop a staged roadmap for transitioning Ontario's gas network to a low-carbon future in line with technical and economic barriers and opportunities. The assessment comprises the entirety of EGI's gas pipeline network in Ontario:
- 78 214 km of gas distribution main lines
- 66 787 km of gas distribution service lines
- 5 471 km of gas transmission lines

Resources: 3rd party contractor

Solution Impact: By blending hydrogen at strategic locations across EGI's existing gas network, EGI aims to reduce the carbon intensity of its 3.8 million residential, commercial, institutional and industrial customers across over 500 communities in Ontario.

Project Timing & Execution Risks:
Study to be completed in 2026

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - Growth - Hydrogen Blending
Investment Stage	Initial		

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	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

Spend Profile

Name	Net Base Capex O (CA)
Enbridge Gas Distribution System Hydrogen Feasibility Study	$ 12,000,000

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ -	$ 4,000,000	$ 4,000,000	$ 4,000,000	$ -	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Report Generation Date: 5/30/2022

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
48714	**2023**	**10**

Investment Name
Hagar Cold Box

Investment Description

Issue/Concern/Opportunity: The Cold Box is several heat exchangers in series used to cool the natural gas feedstock to -160 degrees Celsius at which point the natural gas turns into a liquid. The Cold Box is the core of the Liquefied Natural Gas (LNG) station and is necessary to produce LNG. The consequence of a Cold Box failure is dominated by customer impact. Risk of associated failure is heavily influenced by thermal cycling and operational hours. Over its 50 years of operation, the Cold Box has amassed 140,000 operational hours. Significant failure modes include leakage of natural gas or refrigerants out of the piping into the interior of the Cold Box shell reaching potentially explosive levels or heat exchanger cross leaks that reduce the effectiveness of the refrigeration process. Both of these failure modes impair LNG production to the extent the plant cannot meet its annual production requirements. As the Cold Box internals are encased in very densely packed insulation and clad in an outer steel jacket, troubleshooting and repair of either of these failure modes is extremely difficult and time consuming.

Assets: Cold Box

Related Programs: N/A

Recommended Alternative Description

Scope of Work: This project involves replacement of the Cold Box.

Solution Impact: Considering the complex nature of internal repair or replacement of the Cold Box, a reactive response to internal leakage would render the liquefaction process out of production and unable to meet its regulated requirements for at least an operational season. Due to the age of the plant, the replacement of an individual component such as the Boil Off Gas (BOG) Compressor introduces a risk of the compatibility of new equipment with the existing balance of the plant. This could result in a change in project scope or an approach that favours broader plant renewal.

Resources: Projects will work with a third-party engineering firm to complete the design and a contractor to complete the field work. Operations will support Major Projects as required.

Project Timing & Execution Risks: The proposed timing to complete the on-site work is during the second and third quarters of the year. Design and ordering of long-lead items will need to occur a year in advance.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - LNG - Integrity
Investment Stage	Long Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_53 - Union South Storage
	Asset Program (EGI)	LNG - Integrity
	Asset Class (EGI)	LNG
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

Spend Profile

Name	Net Base Capex O (CA)
Hagar Cold Box	$ 11,000,000

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,500,000	$ 8,500,000
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Report Generation Date: 5/30/2022

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
49955	2023	10

Investment Name: Hagar JVG Compressor Upgrade

Investment Description

Issue/Concern/Opportunity: The Boil Off Gas (BOG) Compressor is one of the two compressors used to power the refrigerant process which cools the natural gas feedstock to -160 degrees Celsius at which point the natural gas turns into a liquid. The BOG Compressor was also used to recover BOG (i.e., natural gas vapours) from the Liquefied Natural Gas (LNG) storage tank which occurs on a continuous basis due to the ambient warming of the tank exterior. In 2012, a separate compressor was installed to manage the LNG storage tank boil off gas.

The BOG Compressor is necessary to produce LNG. The consequence of compressor failure is dominated by customer impact. Risk associated with failure of the BOG compressor is heavily influenced by the time of year, weather severity and time to mitigate the failure. Over its 50 years of operation, the 240 horsepower Ingersoll Rand BOG Compressor has amassed 325,000 operational hours. The compressor is obsolete; and, although normal wear components are still available in the marketplace, core compressor replacement parts such as cylinders, crankshafts, and pistons, etc., required to support a critical failure are no longer manufactured by the original equipment manufacturer (OEM). In the event of a critical failure, securing used parts (which are rare) or aftermarket custom machining services are the only options for a timely repair. This was the case in 2017 when an aftermarket service was solicited to develop a weld and machine repair of a compressor cylinder which had failed. The aftermarket service was able to design a custom repair which took three months to complete. In the event that the cylinder is not repairable, a custom-designed aftermarket casting or a complete replacement of the compressor may be options. These options would take the plant out of service for at least one operational season, rendering the plant unable to perform its regulated requirements.

Assets: BOG Compressor

Related Programs: N/A

Recommended Alternative Description

Scope of Work: Replacement of the 240 horsepower Boil Off Gas (BOG) Compressor (JVG)

Solution Impact: Mitigate the risk of a critical part failure that is non-repairable due to obsolescence.

Resources: Projects will work with a third-party engineering firm to complete the design and a contractor to complete the field work. Operations will support Major Projects as required.

Project Timing & Execution Risks: The proposed timing is to complete the on-site work during the second and third quarters. Design and ordering of long-lead items will need to occur a year in advance.
Due to the age of the plant, the replacement of an individual component such as the BOG compressor introduces a risk of the compatibility of new equipment with the existing balance of the plant. This could result in a change in project scope or an approach that favours broader plant renewal.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - LNG - Replacements
Investment Stage	Long Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_92 - Union North Storage
	Asset Program (EGI)	LNG - Replacements
	Asset Class (EGI)	LNG
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

Spend Profile

Name	Net Base Capex O (CA)
Hagar JVG Compressor Upgrade	$ 26,820,000

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,500,000	$ 14,592,000
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Report Generation Date: 5/30/2022

ENBRIDGE Investment Summary Report	Investment Code	Report Start Year	Number of Years
	48709	2023	10
	Investment Name		
	Hagar KVGR and Cycle Mix Cooler		

Investment Description

Issue/Concern: The Hagar Liquefied Natural Gas (LNG) Plant was installed in 1968 to provide security of supply to the Sudbury industrial and distribution markets. The KVGR Compressor is one of the two compressors used to power the refrigerant process which cools the natural gas feedstock to -160 degrees Celsius at which point the natural gas turns into a liquid. The KVGR Compressor is necessary to produce LNG. The consequence of compressor failure is dominated by customer impact. Risk associated with failure of the KVGR Compressor is heavily influenced by the time of year, weather severity and time to mitigate the failure. Over its 50 years of operation, the 1,500 horsepower Ingersoll Rand KVGR Compressor has amassed 140,000 operational hours. The compressor is obsolete; and, although normal wear components are still available in the marketplace, core compressor replacement items such as cylinders, crankshafts, and pistons, etc., required to support a critical failure are no longer manufactured by the original equipment manufacturer (OEM). In the event of a critical failure, aftermarket, custom machining services are the only option for repair. In the event custom machining services are not able to make a repair, a custom designed aftermarket casting option or complete replacement of the compressor would he required rendering the LNG plant out of service for at least one operational season and rendering the plant unable to perform its regulated requirements.

Assets: Compressor and Cycle Mix Cooler

Related Programs: N/A

Recommended Alternative Description

Scope of Work: Replacement of the 1,500 horsepower KVGR Compressor

Solution Impact: Mitigate the risk of a critical part failure that is non-repairable due to obsolescence.

Resources: Projects will work with a third-party engineering firm to complete the design and a contractor to complete the field work. Operations will support Major Projects as required.

Project Timing & Execution Risks: The proposed timing to complete the on-site work is during the second and third quarters of the year. Design and ordering of long-lead items will need to occur a year in advance. Due to the age of the plant, the replacement of an individual component such as the compressor introduces a risk of the compatibility of new equipment with the existing balance of the plant. This could result in a change in project scope or an approach that favours broader plant renewal.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - LNG - Replacements
Investment Stage	Long Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_92 - Union North Storage
	Asset Program (EGI)	LNG - Replacements
	Asset Class (EGI)	LNG
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

Spend Profile

Name	Net Base Capex O (CA)
Hagar KVGR and Cycle Mix Cooler	$ 31,820,000

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,500,000	$ 17,592,000
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Report Generation Date: 5/30/2022

ENBRIDGE Investment Summary Report	Investment Code	Report Start Year	Number of Years
	8701	2023	10
	Investment Name		
	Kelfield Operations Centre - Land Purchase		

Investment Description

Issue/Concern: The Kelfield office, owned by Enbridge Gas Inc. (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 rebuild 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.

Assets: 40 Kelfield St., Etobicoke, ON.

Related Program: N/A

Recommended Alternative Description

Scope of Work:
The assets in scope are located at 40 Kelfield St., Etobicoke, ON. The nature of work is to purchase adjacent property.

Solution Impact:
Purchasing the extra land will ensure adequate yard area for current activities.

Timing & Execution Risks:
The project duration is 3 months (i.e., 0 – 3 months for site acquisition).

Expenditures:
The total cost for the project is $47M net capital. The project costs are based on a Class 5 estimate.

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

Spend Profile

Name	Net Base Capex O (CA)
Kelfield Operations Centre - Land Purchase	$ 25,000,000

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ -	$ -	$ -	$ 25,000,000	$ -	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Report Generation Date: 5/30/2022

ENBRIDGE Investment Summary Report	Investment Code	Report Start Year	Number of Years
	737226	2023	10
	Investment Name		
	Kelfield Operations Centre - New Building		

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 St, Etobicoke, ON.

Related Program: N/A

Recommended Alternative Description

Scope of Work:
The assets in scope are located at 40 Kelfield St, Etobicoke, ON. The nature of work is sell the existing property, development of adjacent property, construction and fit-up of a new building.

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 & Execution Risks:
The Project duration is 33 months as described below:
0 – 3 months: Programming, design development
3 – 9 months: Site plan agreement, permit & tender documents, permit and tender process
9 – 11 months: Contract award and winter contingency as required
11 – 25 months: Construction
25 – 27 months: Fit-up and occupancy
27 – 33 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 $22M 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	Initial		

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

Spend Profile

Name	Net Base Capex O (CA)
Kelfield Operations Centre - New Building	$ 22,000,000

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ -	$ -	$ -	$ 12,000,000	$ 10,000,000	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Report Generation Date: 6/6/2022

ENBRIDGE Investment Summary Report	Investment Code: 501813	Report Start Year: 2023	Number of Years: 10
	Investment Name		
	Kennedy Road Expansion		

Investment Description

Issue/Concern/Opportunity:
Overall, the existing building at the Kennedy Road facility is too small to meet current Enbridge Gas Inc. (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 Facility Condition Index (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 Adequacy Index (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 rebuild 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.

Assets: 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 neighbouring 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.

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.

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 $38.0M 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.

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

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
501813	2023	10

Investment Name

Kennedy Road Expansion

Spend Profile

Name	Net Base Capex O (CA)
Kennedy Road Expansion	$ 46,595,406

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ 250,000	$ 19,750,000	$ 18,000,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Report Generation Date: 5/30/2022

ENBRIDGE Investment Summary Report	Investment Code: 3642	Report Start Year: 2023	Number of Years: 10
	Investment Name: SMOC/Coventry Facility Consolidation		

Investment Description

Issue/Concern/Opportunity:
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 Enbridge Gas Inc. (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, and 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, and 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, and 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

Scope of Work: Eastern Region Consolidated Facility Project
This project requires selling both the SMOC and Coventry Road properties, purchasing a property suitable in size (approximately 7 acres) and building a new 70,000 square-foot 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.

Resources: External professional resources for design and engineering along with a construction company will be contracted for the project. Historically, Enbridge Gas Inc. (EGI) has retained architectural and engineering consulting services and general construction contractors for the execution of similar projects.

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.

Project Timing & Execution Risks:
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 $36M 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.

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)	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

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
3642	2023	10

Investment Name

SMOC/Coventry Facility Consolidation

Spend Profile

Name	Net Base Capex O (CA)
SMOC/Coventry Facility Consolidation	$ 36,040,000

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ 11,000,000	$ 5,000,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Report Generation Date: 5/30/2022

ENBRIDGE Investment Summary Report	Investment Code: 3640	Report Start Year: 2023	Number of Years: 10
	Investment Name: Station B New Building		

Investment Description

Issue/Concern/Opportunity:
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.

Assets: 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 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.

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.

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 $45.6 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.

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

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
3640	2023	10

Investment Name

Station B New Building

Spend Profile

Name	Net Base Capex O (CA)
Station B New Building	$ 43,666,884

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ 20,000,000	$ 9,000,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Report Generation Date: 5/30/2022

ENBRIDGE Investment Summary Report	Investment Code	Report Start Year	Number of Years
	8681	2023	10
	Investment Name		
	Thorold Regional Office - Building & Site		

Investment Description

Issue/Concern/Opportunity: The administrative office in Thorold is an owned property that is in physically good condition, but operating at full occupancy offering minimal room for growth. This office was last renovated 18 years ago and the environment is in need of a refresh. Since this renovation, EGI office standards have evolved and include a focus on natural light and views to the outdoors. The facility does not meet current EGI office standards. In addition, the parking lot at the Thorold administrative facility does not meet current standards or growth demands. The parking lot currently accommodates 127 vehicles and does not accommodate the growth requirements for both operations and administrative staff parking. During peak periods, such as training sessions, department meetings, and special events, staff is required to park off site due to the limited space. In the winter after heavy snow, up to 10 parking spaces are lost until the snow is hauled away off-site.

Physical Obsolescence: The acceptable Enbridge standard for the physical condition is an FCI of 0 to 5%. The current FCI of the facility based on this study is 3.09%; therefore, the physical condition of the facility meets Enbridge 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 59% which is marginally considered correctable at the current location, without consideration of other factors, including adequacy of land size and the FCI.
-Site: The site does not meet operational requirements for vehicular circulation. The yard size is smaller than EGI standard yard size requirements. The current usable yard size is 1.7 acres. EGI standard yard size is 2.5 acres, however there is at least one acre of landscaped area that could be reconfigured to accommodate site deficiencies.

Asset: 3401 Schmon Parkway, Thorold, Ontario.

Related Program: N/A

Recommended Alternative Description

Scope of Work:
The assets in scope are located at 3401 Schmon Parkway, Thorold, Ontario. The nature of work is interior renovation and furnishings and expanding the employee parking lot. This project will correct physical and functional deficiencies by renovating the current office space and expanding the parking lot. Physical and functional standards can be met more cost-effectively by renovating the current office space and site. The renovated facility will use less energy and emit less greenhouse gases.

Expenditures: Total capital expenditure for this Project is estimated to be $16.5M 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. The 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.

Solution Impact: The renovation will extend the asset useful life by 15 years.

Project Timing & Execution Risks: The project duration is 12 months as described below:
0 to 2 months: Programming and design development
2 to 5 months: Permit and tender documents
5 to 7 months: Award, tender and permit process
7 to 11 months: Construction
11 to 12 months: Fit-up and occupancy

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)	80 - Niagara
	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)	
	Third Party Relocation (EGI)	
	Program work with sufficient history and risk to warrant continuation (EGI)	

Spend Profile

Name	Net Base Capex O (CA)
Thorold Regional Office - Building & Site	$ 16,500,000

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ 250,000	$ 250,000	$ 5,000,000	$ 8,000,000	$ 3,000,000	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ 600,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Report Generation Date: 5/30/2022

ENBRIDGE Investment Summary Report	Investment Code	Report Start Year	Number of Years
	8782	2023	10
	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 vapour intrusion, and comfort and 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.

Assets: 500 Consumers Rd., North York, ON

Related Program: N/A

Recommended Alternative Description

Scope of Work: The assets in scope are located at 500 Consumers Rd., 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 Facility Condition Index (FCI) and Adequacy Index (AI) show the building and site deficiencies are correctable by the following activities:
- Renewing the building's main mechanical system
- Adding two elevators
- Renovating the three main staircases
- Replacing the building envelope

Resources: External professional resources for design and engineering as well as a construction company will be contracted for the project. Historically, Enbridge Gas Inc. (EGI) has retained architectural and engineering consulting services and general construction contractors for the execution of similar projects.

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 $26M net capital. Construction costs are determined from facility assessment reports and architectural consultant budget forecasts and using marketplace comparisons. Project costs are based on a Class 5 estimate.

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

Spend Profile

Name	Net Base Capex O (CA)
VPC Core and Shell	$ 26,000,000

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,000,000	$ 10,000,000	$ 6,000,000
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,000,000	$ 1,000,000

Report Generation Date: 5/30/2022

ENBRIDGE Investment Summary Report	Investment Code	Report Start Year	Number of Years
	100621	2023	10
	Investment Name		
	Dawn Administrative Centre		

Investment Description

Issue/Concern/Opportunity: The Dawn admin centre on Bentpath Line is an owned property in a good location 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 Enbridge Gas Inc. (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 16.95%. 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 28%.

Functional Obsolescence – Site: The area occupied by the building is separated from the adjacent functions with metal fence complete with barb wire. The building occupies approximately 7.5% of 233,541 SF fenced site area. The two driveways to the south and east of the building act as main entry and exit only servicing visitors and employees. There are four access points from the south and east driveway that lead to the front parking lot. The parking area consists of 68 parking spaces and is considered adequate to accommodate staff and visitors. There is no yard associated with the building due to its unique function as an office building with no industrial components. The building is located in the underground gas storage zone. It was reported by staff the proximity of the building to the underground gas storage is of concern to staff and relocation to an area outside the storage zone is desirable.

Assets: 3332 Bentpath Line, Tupperville, ON.

Related Program: N/A

Recommended Alternative Description

Scope of Work: Build new facility elsewhere on the Dawn campus. The current Asset Management Plan has allocated funds in 2021 and 2022 to fulfill the strategy. This presents the safest, most cost-effective solution for maintaining a Category 1 facility.

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.

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 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 $13M 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.

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_02 - Chatham
	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

Spend Profile

Name	Net Base Capex O (CA)
Dawn Administrative Centre	$ 13,000,000

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ -	$ -	$ -	$ -	$ 1,000,000	$ 12,000,000	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Report Generation Date: 5/30/2022

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
101136	**2023**	**10**
Investment Name		
New London Site		

Investment Description

Issue/Concern/Opportunity: 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 (approximately 7 to 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.

Resources: External professional resources for design and engineering along with a construction company will be contracted for the project. Historically, Enbridge Gas Inc. (EGI), has retained architectural and engineering consulting services and general construction contractors for the execution of similar projects.

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 to 40 years.

Project Timing & Execution Risks

Timing: The total project duration is 30 months:
0 – 3 months: Programming, design development, and 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 $42.6M 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.

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_04 - London
	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

Spend Profile

Name	**Net Base Capex O (CA)**
New London Site	$ 42,650,000

Account Type	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Base CAPEX O	$ -	$ 1,500,000	$ 18,500,000	$ 20,000,000	$ -	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Report Generation Date: 5/30/2022

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
100709	**2023**	**10**

Investment Name: Sudbury Regional Operations Centre

Investment Description

Issue/Concern: The Sudbury depot on Falconbridge Road is an owned property in a good location, 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 8.49%. 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 13%.

Functional Obsolescence – Site: The site is 1.9 acres and is serviced by two driveways off of Westbourne Street. The northern driveway is a two way driveway that provides access to the front parking lot for both employees and staff. The southern driveway is equipped with card access into the yard servicing only employees. The site consists of a main office and warehouse building. The parking and yard are arranged such that the main employee and staff parking is located to the north east of the building with additional staff parking and yard to the south of the building.

Asset: 828 Falconbridge Road, Sudbury, ON.

Related Program: N/A

Recommended Alternative Description

Scope of Work: Correct physical and functional deficiencies by renovating the existing facility. This Project will correct physical and functional deficiencies by renovating the current office space. Physical and functional standards can be met more cost-effectively by renovating the current office space and site. The renovated facility will use less energy and emit less greenhouse gases.

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.

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

Expenditures: Total capital expenditure for this Project is estimated to be $11.6M 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. The Project costs are based on a Class 5 estimate.

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_43 - Sudbury & S.S. Marie
	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)	
	Third Party Relocation (EGI)	
	Program work with sufficient history and risk to warrant continuation (EGI)	

Spend Profile

Name	Net Base Capex O (CA)
Sudbury Regional Operations Centre	$ 11,600,000

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ -	$ -	$ 1,600,000	$ 10,000,000	$ -	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Report Generation Date: 5/30/2022

ENBRIDGE Investment Summary Report	Investment Code: 102291	Report Start Year: 2023	Number of Years: 10
	Investment Name: Contract Market Harmonization		

Investment Description

Issue/Concern/Opportunity: The OEB MAADs decision specified that EGI shall file a proposal for rate harmonization in its next rebasing application. In order to harmonize contract market rates, services must also be harmonized. Enbridge believes that harmonizing and aligning services for the contract market will improve the customer experience for contract customers by reducing the number of systems they must transact in, aligning policies across rate zones, and simplifying processes. If the proposal filed as part of 2024 Rebasing is approved, this project will be required to implement the approved rates and services in the systems listed below. By implementing this project coincident with the Contract Market Systems – Technology Obsolescence project, the investment of capital is optimized.

Assets: TIS Business Solutions. EnTRAC, URICA, Enerline, CARE, ConTrax, GDAR, SAP- CIS, SAP-ERP, Oracle Financials, Data Marts are examples of the systems impacted

Related Program: Contract Market Systems - Technology Obsolescence #736942, Rates and Service Harmonization Project #76081

Recommended Alternative Description

Scope of Work: Currently, Enbridge Gas Inc (EGI) has 3 different rate zones (EGD, Union North, Union South), 11 separate service designs and 43 rate classes. This results in complex business and accounting processes. This project will implement changes to several EGI business applications to implement harmonized services, rate zones, and rate classes.

This project, in conjunction with the Contract Market - Technology Obsolescence Project, is required to provide consistent services with common design elements for customers in all areas of the franchise. The simplified, consistent services will enhance the customer experience, provide more flexibility for customers, and reduce the complex variations in the existing services and rates. Contract market harmonization will facilitate harmonized business processes, reduced system complexity, and will reduce the level of effort associated with ongoing business and TIS support. Detailed information regarding the service and rate harmonization and the associated benefits will be filed with EGI's 2024 rebasing application.

Several business applications are impacted based upon the changes proposed:
-ConTrax/CARE/GDAR/Enerline - The Union rate zone business applications that perform contracting, billing and gas management/nominations functions, including customer facing portals.
-EnTRAC/Urica/GDAR – The EGD rate zone business applications that perform contracting and gas management/nominations functions, including customer facing portals.

This functionality will be enabled in conjunction with the Contract Market Systems - Technology Obsolescence project, which will coincidentally integrate the above legacy company applications and replace aging technologies. These business applications must be integrated to allow for the harmonization of rate zones, rate classes and services as well as a single customer portal. If the applications are not integrated, EGI will need to make changes to multiple applications to align them with the harmonized services and business processes. A single customer portal would remain a requirement regardless of the underlying business applications. In addition, some of the proposals for service harmonization may not be able to be implemented. For example, the scenario where customers or contracts cross between the existing rate zones. In addition to the primary business applications, there will also be changes required to downstream processes and applications such as gas accounting, QRAM, and financial reporting to align with the harmonized rates and services.

This project will follow TIS project methodologies as developed and governed by the Project Management Office.

Resources: Project Manager, Business Analysts, Business Systems Support Team, Customer Care SMEs, Regulatory SMEs, Finance SMEs, TIS SMEs, Energy Services SMEs, Enterprise Architecture, Solutions Architecture, Data & Analytics, Report Developers, AMS provider, Solutions Integrator, Audit, Testing, Organizational Change Management (OCM)

Solution Impact: EGI currently has 3 Rate Zones, 11 Separate Service Designs and 43 Rate Classes. This project will implement the required changes to enable service and rate harmonization.

Project Timing & Execution Risks:
-Project expected to start late 2023, and will continue into 2024 pending the approval of Rate and Service Design by the OEB as part of the 2024 Rebasing Application. A key dependency is the Contract Market - Technology Obsolescence Project. In order to harmonize services, EGI must consolidate and modernize the contract rate billing, contracting, GDAR and gas management/nominations applications. Target implementation date is Q2 2026. Project milestones for design, build, test and delivery to be developed once project approved, team established, and project initiated.
-Risks include resource constraints, competing priorities, OEB approval of service and rate harmonization as submitted by EGI.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - TIS - TIS Business Solutions
Investment Stage	Long Term Planning		

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

Spend Profile

Name	Net Base Capex O (CA)
Contract Market Harmonization	$ 14,760,000

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ 2,000,000	$ 5,000,000	$ 5,000,000	$ 2,760,000	$ -	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Report Generation Date: 6/2/2022

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
736942	**2023**	**10**

Investment Name

Contract Market Systems - Technology Obsolescence

Investment Description

Issue/Concern/Opportunity:
This project will consolidate the contracting, gas management/nominations and billing applications at EGI. The Contract to Cash processes are currently using aging and disparate systems for groups such as Large Volume Contracting, Gas Supply and Storage and Transmission Sales. This new platform and integrated systems will then enable Rate and Service Harmonization (if approved) and further enhance the customer experience, and reduce total cost of ownership.

Justification: Many of these systems are 20-30 years old and are built using technology that is or will become unsupported in the near future and requires upgrading. Failure to refresh aging systems and applications puts our business at risk with an increased chance of service outages, degraded performance, business and customer interruptions, increased costs, difficulty in acquiring support and ability to address cybersecurity risks.

Assets: Legacy (EGD&Union) Contract Management and Billing (EnTrac, URICA, ConTrax) and associated Legacy (LEGD&LUG) Gas Management systems (CARE, Enerline) will be replaced and/or modified by SAP modules and decommissioned (EGI may still retain this system name/brand for the customer facing portal, even if the underlying technology is replaced). New system integrations with CIS/SAP/Oracle/Cost of Gas, reporting, and data warehouse are examples of additional changes and systems impacted.

Related Investments: Contract Market Harmonization Project #102291

Recommended Alternative Description

Scope of Work:
Legacy (LEGD&LUG) Contract Management and Billing (EnTrac, URICA, ConTrax) and associated Legacy (LEGD&LUG) Gas Management systems (CARE, Enerline) will be replaced and/or modified by SAP modules and decommissioned. New system integrations with CIS/SAP/Oracle, reporting, and data warehouse are examples of additional changes and systems impacted.

TIS benefits:
-Improved support and sustainment and cyber security.
- Decommissioning of servers and legacy applications.
- Reduced complexity and total cost of ownership for Contract and Gas Management systems and support

Business Benefits:
- Alignment, simplification and automation of business processes
- Easier to train staff, one set of unified processes and procedures
- Reduction in testing efforts, eliminating multiple systems and applications
- Improved customer experience and ease of use when transacting with Enbridge systems
- Reduced chance of service outages and degraded system performance

Resources: Customer Care Large Volume SME's, Energy Services Gas Management SME's, Finance, TIS SME's, Enterprise Architect, Data and Analytics Arch, Network and Security, Change Management, Project Manager, System Integrator, (Legal, Finance, Regulatory SME's as required)

Solution Impact: This project is required to align disparate and aging systems which must be replaced in order to ensure that contract market customers can continue to transact. Without this project, transactions such as contracting, gas management, and billing are at risk of service outage, degraded performance, cyber security risk, and increased cost of sustainment. This project also delivers a modernized technology platform that will enable the Contract Market Harmonization project which implements the proposed harmonized rates and services for the contract market. The implementation of this project and the Contract Market Harmonization project will deliver improved customer experience, simplified processes and aligned services on a modernized and reliable technology platform.

Project Timing & Execution Risks:
Timing- Project activities are expected to start in 2023, with the teams proving out the technology, and process mining tools, and reviewing business processes for standardization. An Request For Proposal (RFP) will be developed and selection the System Integrator (SI) for a project implementation date in 2026.

Risks- Competing priorities and resource constraints, continuity of resources on the project team to help mitigate schedule impacts for knowledge gaps (current state/future state, design/testing) and any potential rework as a result.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - TIS - TIS Business Solutions
Investment Stage	Initial		

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	Yes
	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
736942	2023	10

Investment Name

Contract Market Systems - Technology Obsolescence

Spend Profile

Name	Net Base Capex O (CA)
Contract Market Systems - Technology Obsolescence	$ 53,240,000

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ 7,450,000	$ 17,830,000	$ 17,830,000	$ 10,130,000	$ -	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Report Generation Date: 6/2/2022

ENBRIDGE Investment Summary Report	Investment Code	Report Start Year	Number of Years
	736081	2023	10
	Investment Name		
	General Service Rebasing Changes		

Investment Description

Issue/Concern/Opportunity: The OEB MAADs decision specified that EGI shall file a proposal for rate harmonization in its next rebasing application. EGI believes that harmonizing rates will improve the customer experience for general service customers by simplifying rates, processes, and improved cost transparency. If the proposal filed as part of 2024 Rebasing is approved, this project will be required to implement the proposal in the EGI systems listed below.

Assets: TIS Business Solutions. CIS-SAP, Kubra, SAP-ERP, Oracle Financials, EnTRAC, ConTrax, GDAR, MyAccount, Data Marts (BBDM, CTDS, BW, EDW, etc), Guardian, Load Gathering, Synergee, Get Connected are examples of the systems impacted.

Related Program: N/A

Recommended Alternative Description

Scope of Work: Currently, Enbridge Gas Inc. (EGI) has three different rate zones (EGD, Union South and Union North) and six general service customer classes across eight rate categories. This results in complex business and accounting processes. This project will implement changes to several EGI systems to implement a harmonized model with a single rate zone for EGI, two customer classes (rate categories – Small Demand and General Demand) and harmonized rates. This will simplify rates for customers and related business and accounting processes such as QRAM. This project will follow TIS project methodologies as developed and governed by the Project Management Office.

Benefits include improved customer experience due to simplification of rates and improved cost transparency, business process simplification resulting from one set of terms and conditions of service across entire EGI franchise area, simplification of accounting processes including QRAM, forecasting, financial reporting, and easier to administer regulatory application and OEB review processes.

Resources: Project Manager, Business Analysts, Business Systems Support Team, Customer Care SMEs, Regulatory SMEs, Finance SMEs, TIS SMEs, Energy Services SMEs, Finance SMEs Enterprise Architecture, Solutions Architecture, Data & Analytics, Report Developers, AMS provider, Solutions Integrator, Audit, Testing, Organizational Change Management (OCM)

Solution Impact: This project will implement the required changes to enable a single rate zone for EGI with two customer classes (Rate Categories – Small Demand and General Demand) and the harmonization of general service rates.

Project Timing & Execution Risks:
-Project to start no later than January 2024, with approval from the OEB of General Service Rate Harmonization. Target implementation date Q2 2025. Project milestones for design, build, test and delivery to be developed once project approved, team established, and project initiated.
-Risks include resource constraints, competing priorities, OEB approval of harmonization as submitted by EGI.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - TIS - TIS Business Solutions
Investment Stage	Long Term Planning		

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

Spend Profile

Name	Net Base Capex O (CA)
General Service Rebasing Changes	$ 16,000,000

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ -	$ 14,000,000	$ 2,000,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Report Generation Date: 6/2/2022

ENBRIDGE Investment Summary Report	Investment Code	Report Start Year	Number of Years
	102364	2023	10
	Investment Name		
	Records Management Technology Obsolescence (2024-2026)		

Investment Description

Issue/Concern/Opportunity:
The Records Management technologies host information about EGI gas carrying asset which are critical to drive integrity and operation of these assets. In addition, the information is used by the Integrity group to determine asset condition which will inform the asset life cycle strategies used to develop the 10 year Asset Plan with focus on safe and reliable operations of EGI assets. The Records Management technologies is made up of multiple systems which will become vendor unsupported between 2024 to 2026 and requires upgrades to reduce technology complexity, cyber risk, and to enable process optimization. Failure to maintain software warranty will increase the likelihood of system failures, increase outages, degraded performance and increase vulnerability to cybersecurity attacks.

The objective of the Records Management (Asset Records) Technology Obsolescence project is to align the key systems and high level process for gas carrying asset records which are used to support Operations in performing maintenance, and construction work as well as Engineering to conduct analysis and produce asset plans. This will be enabled through the selection of an integrated suite of applications that satisfy all technical and business requirements.

Assets:
TIS Business Solutions, examples of the core systems impacted:
-ESRI ArcServer GIS (Packaged Software) 10.8 (2026 retirement)
-Hexagon GIS (Packaged Software) G/Technology (2024 retirement)
-iViewer (Custom)
-ProjectWise Connect (Packaged Software) (2024 retirement)

Related Program: N/A

Recommended Alternative Description

Scope of Work :
The scope and objective of the Records Management (Asset Records) Technology Obsolescence project is to address the technology obsolescence and align the key systems for gas carrying asset records. This will be enabled through the selection of an integrated suite of applications that satisfy all technical and business requirements. The work will consist of upgrading software to the latest supported versions as well as incorporate the opportunities to optimize business processes by leveraging new capabilities offered by the software.

The initiative will follow TIS project methodologies as developed and governed by the Project Management Office, including, signed charter and a project plan covering the activities of design, build, test and implementation.

Benefits:
EGI will be able to leverage advancements in technology which could provide further benefits in optimizing business processes. As such the following benefits are estimated: Technology savings of $975k annual savings related to a reduction in technology, licenses, and infrastructure. Business savings are comprised of $1,000,000 related to drafting efficiencies in Distribution Operations; $400,000 related to Records Management team savings in Engineering & STO; $50,000 related to efficiencies in Engineering Construction/Drafting and Capital Development; all savings have been derived using an ~8% rate reduction

Resources:
Project Managers, Enterprise Architecture, System Integrators, Operations SMEs, Asset Records SMEs, TIS SMEs, Vendor Professional Services, External Contractors

Solution Impact:
This will impact Operations and Engineering employees as well as third-party alliance partners who require asset records to perform their work. This will also impact teams within the organization that produce and manage asset records throughout the asset lifecycle, such as the Records Management team and Asset Integrity. The solution will implement the latest version of software where software bugs have been resolved and the technology would be compatible to the latest hardware thereby ensuring a more secure, reliable, and sustainable platform. With the upgrades there are advancements in software technology introducing new capabilities that will optimize business processes.

Project Timing & Execution Risks:
This project is expected to start in 2024. With design efforts starting January 2024 and in service target date of completion Dec 2026.

Risk: Competing priorities, resource constraints, and business cost pressures.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - TIS - TIS EGI Business Solutions
Investment Stage	Long Term Planning		

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	Yes
	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
102364	2023	10

Investment Name

Records Management Technology Obsolescence (2024-2026)

Spend Profile

Name	Net Base Capex O (CA)
Records Management Technology Obsolescence (2024-2026)	$ 21,550,000

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ -	$ 4,250,000	$ 8,650,000	$ 8,650,000	$ -	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Report Generation Date: 6/2/2022

ENBRIDGE Investment Summary Report	Investment Code	Report Start Year	Number of Years
	6377	2023	10
	Investment Name		
	PCRW:Wells-Upgrade		

Investment Description

Issue/Concern:
Wells at Crowland are much older than other wells at 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 1970s and have continued 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 225 m) plus a surface casing that runs from the surface to a depth of about 20 m. 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. Should the inner casing fail, this provides a poor barrier to gas flow. 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 in.) 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 2 of the 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.

The 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.

Assets: Crowland wells and gathering system.

Related Programs: This investment is under consideration in conjunction with the Distribution Station #3610 Crowland Investment. 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:
The scope of works includes: Drilling applications and well locations studies, design, materials, core sampling, drilling of 2 new wells and wellheads / master valves to 12 existing wells, stimulating 2 new wells and 12 existing wells, and upgrading wellheads for 12 existing wells

Resources:The majority of design and installation work will be performed by third parties.

Solution Impact: Results of the core integrity testing will verify that the confining geological formations are suitable for storage, provide inputs needed to simulate the wells, abandon up to eight existing wells thereby reducing risk.

Risks Reduced:
-Loss of containment from exposed inner casing above the surface level of the well.
-Effects of well casing corrosion, where exposed to corrosive sulphur, can be mitigated more readily with modern wellheads and master valves. This limits pressurized gas leaking through the well casing and contaminating well water at surface with sulphur.
-Effects of deteriorated cement between the casing and rock can be mitigated more readily with modern wellheads 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 the surface.

Project Timing & Execution Risks:
Year 1 - permits, applications, order long lead items, testing and planning
Year 2- Construction
Year 3 - Abdonment

Risks/Assumptions:
-Project schedule is influenced by reservoir pressures, regulatory approvals, and environmental factors.
-Environmental findings may impact execution costs.
-Crowland is located in a marshy area which may impact execution and, subsequently, costs.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - Transmission Pipe & Underground Storage - Replacements
Investment Stage	Executing		

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	CSA Z341.1-14 Section 5.8.7
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

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
6377	2023	10

Investment Name

PCRW:Wells-Upgrade

Spend Profile

Name	Net Base Capex O (CA)
PCRW:Wells-Upgrade	$ 12,780,000

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ 8,500,000	$ 1,750,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ 3,000,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Report Generation Date: 5/30/2022

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
100699	2023	10

Investment Name

Dawn Parkway Expansion Project (Dawn-Enniskillen NPS 48)

Investment Description

Issue/Concern: In response to increased natural gas demand growth along the Dawn Parkway System, the Kirkwall to Hamilton Expansion has a forecast in-service date of 2029 to 2030 and will provide reliable, secure, economic natural gas capacity to meet the growing design day demand of the Dawn Parkway Transmission system which serves both in- and ex-franchise markets.

Assets: Install approximately 17.2 km of NPS 48 internally-coated pipeline from Dawn Compressor Station (10G-301) to Enniskillen Valve Site (11H-301V) on the Dawn Parkway System.

Related Programs: These facilities are incremental to the Kirkwall to Hamilton Expansion (#48654) and timing is dependent on the Dawn Parkway System demands.

Recommended Alternative Description

Scope of Work: Install approximately 17.2 km of NPS 48 internally-coated pipeline from Dawn Compressor Station (10G-301) to Enniskillen Valve Site (11H-301V) on the Dawn Parkway System.

Resources: Projects group to provide project management support from design and planning phase to project execution.

Solution Impact: Capacity is available on the Dawn Parkway System to meet in-franchise growth and customer demand.

Project Timing & Execution Risks:
-Schedule delays due to right-of-way access for survey, ladn aquisition, environmental studies, permitting, and/or issuance of OEB Leave to Construct may put at risk the planned in-service date.
-Further analysis for potential IRPAs.
-This project will follow Kirkwall to Hamilton (48654). It will be based upon studies done by the Transmission System Planning identifying a need for expansion based upon the demands from the study.
-Estimate/ Forecast does not include MOP Upgrade or Dawn Station Work.

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_04 - London
	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	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Spend Profile

Name	Net Base Capex O (CA)
Dawn Parkway Expansion Project (Dawn-Enniskillen NPS 48)	$ 246,634,252

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ -	$ -	$ -	$ -	$ 24,612,151	$ 49,222,260	$ 148,187,690	$ 24,612,151	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Report Generation Date: 5/30/2022

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
48654	**2023**	**10**

Investment Name

Dawn Parkway Expansion Project (Kirkwall-Hamilton NPS 48)

Investment Description

Issue/Concern: In response to increased natural gas demand growth along the Dawn Parkway System, the Kirkwall to Hamilton Expansion has a forecast in-service date of November 1, 2026 and will provide reliable, secure, economic natural gas capacity to meet the growing design day demand of the Dawn Parkway Transmission system which serves both in- and ex-franchise markets.

Assets: The Kirkwall-Hamilton Expansion Project consists of 10.2 km of NPS 48 pipeline from the Kirkwall Valve Site to the Hamilton Valve Site.

Related Programs: N/A

Recommended Alternative Description

Scope of Work: System installation of approximately 10.2 km of NPS 48 internally-coated pipeline from Kirkwall Valve Site (17V-302) to Hamilton Valve Site (18W-601V) on the Dawn Parkway System.

Resources: Projects group to provide project management support from design and planning phase to project execution.

Solution Impact: Capacity is available on the Dawn Parkway System to meet in-franchise growth and customer demand.

Project Timing & Execution Risks: In March 2021, this project was pushed out to 2025 and is forecast for November 1, 2026 in-service date. This project was filed with the Ontario Energy Board (OEB); but due to the global pandemic, there was demand uncertainty and the project ultimately was paused. Further analysis for potential IRPAs. Schedule delays due to right-of-way access for survey, environmental studies, land acquisition. 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	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Spend Profile

Name	Net Base Capex O (CA)
Dawn Parkway Expansion Project (Kirkwall-Hamilton NPS 48)	$ 192,008,405

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ -	$ 19,000,000	$ 38,247,415	$ 115,027,169	$ 16,000,000	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Report Generation Date: 5/30/2022

ENBRIDGE	Investment Code	Report Start Year	Number of Years
Investment Summary Report	49758	2023	10
	Investment Name		
	Panhandle Regional Expansion Project		

Investment Description

Issue/Concern:
To provide reliable, secure, and affordable natural gas supply to meet the growth in Design Day demand of the Panhandle System:

Assets:
i. Dawn Yard: 700 m of 8960 kPa MOP NPS42 station header is required to maintain the maximum sustainable pressure on design day. This header will also provide operational flexibility and security of supply to the Panhandle system.
ii. Panhandle Take-off Station: The existing station will be modified to meet the new system capacity demand requiring measurement, odourization and regulation assets.
iii. Dover Transmission Station: This existing regulating station will be modified to connect the new NPS 36 pipeline to the upstream system. Flow measurement equipment will also be added to the station.
iv. Panhandle Loop : 19 km of NPS 36 6040 kPag MOP pipeline will parallel the NPS 20 from Dover Transmission station to a new valve site at Richardson Sideroad.
v. Richardson Sideroad Valve Site: A new valve site is required at the end of the NPS 36 Panhandle loop to connect to the existing NPS20 mainline. Isolation valves and launcher/receiver facilities will be installed at this location.

Related Programs: Other PREP Investments: #735972 & 736923

Recommended Alternative Description

1. Scope: To provide reliable, secure, and affordable natural gas supply to meet the growth in Design Day demand of the Panhandle System:

i. Dawn Yard: 700 m ofNPS 42 8960 kPa MOP station header is required to maintain the maximum sustainable pressure on design day. This header will also provide operational flexibility and security of supply to the Panhandle system.
ii. Panhandle Take-off Station: The existing station will be modified to meet the new system capacity demand requiring measurement, odourization and regulation assets.
iii. Dover Transmission Station: This existing regulating station will be modified to connect the new NPS 36 pipeline to the upstream system. Flow measurement equipment will also be added to the station.
iv. Panhandle Loop : 19 km of 6040 kPag MOP NPS36 pipeline will parallel the NPS 20 from Dover Transmission station to a new valve site at Richardson Sideroad.
v. Richardson Sideroad Valve Site: A new valve site is required at the end of the NPS 36 Panhandle loop to connect to the existing NPS20 mainline. Isolation valves and launcher/receiver facilities will be installed at this location.

2. Resources:
This project will be internally managed by EGI staff. Construction work, such as well drilling and new pool piping installation, will be performed by contractors.

3. Solution Impact:
Expansion of the Panhandle system provides customers with increased access to diversity, reliability and security of supply of the Dawn Hub.

4. Project Timing & Execution Risks:
This project starts 2021 with its feasibility endorsed in Q2 2022. Construction will commence in 2023 . The expected in-service date is Fall 2023.

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_02 - Chatham
	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	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Spend Profile

Name	Net Base Capex O (CA)
Panhandle Regional Expansion Project	$ 197,451,236

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ 167,263,803	$ 8,592,570	$ 67,613	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Report Generation Date: 5/30/2022

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
736923	2023	10

Investment Name

Panhandle Regional Expansion Project - Leamington Interconnect

Investment Description

Issue/Concern/Opportunity:
To provide reliable, secure, and affordable natural gas supply to meet the growth in Design Day demand of the Panhandle System,

Assets:

i) Leamington Interconnect : 12 km of 6040 kPag MOP NPS16 pipeline connecting the Leamington North Line, Leamington North Loop, Mersea Line and Kingsville East Line.

ii. Leamington Interconnect Valve Sites: Three new valve sites with isolation valves are required to connect to each of the existing laterals (1. Leamington North Line and Leamington North Loop, 2. Mersea Line and 3. Kingsville East Line). Launcher/receiver facilities will be installed at location 1 and 3.

Related Program: Not Applicable

Recommended Alternative Description

1. Scope Install approximately 11 km of NPS 16 connecting Kingsville East Line, Mersea Line and the Leamington North Lines.

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.

2. Resources:
This project will be internally managed by EGI staff. Construction work, such as well drilling and new pool piping installation, will be performed by contractors.

3. Solution Impact:
Expansion of the Panhandle system provides customers in the Leamington and Kingsville area with increased access to diversity, reliability and security of supply of the Dawn Hub.

4. Project Timing & Execution Risks:
This project starts 2021 with its feasibility endorsed in Q2 2022. Construction will commence in 2024 . The expected in-service date is Fall 2024.

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_01 - Windsor
	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	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Spend Profile

Name	Net Base Capex O (CA)
Panhandle Regional Expansion Project - Leamington Interconnect	$ 55,278,330

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ 12,242,784	$ 39,598,802	$ 3,047,378	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Report Generation Date: 6/2/2022

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
100086	2023	10

Investment Name: Panhandle Line Replacement

Investment Description

Issue/Concern:
Enbridge Gas Inc.'s (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 internally inspected to check for the presence of the primary threat of internal corrosion; such inspection cannot be achieved given the configuration of the asset. 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 (Canada Energy Regulator-regulated crossing)

Related Programs: N/A

Recommended Alternative Description

Scope of Work: Replacement of the twin NPS 12 Crossings with a single pipeline of equivalent capacity.

Resources: Projects group to provide project management support from design and planning phase to project execution.

Solution Impact: The principal risk is the lack of In-line Inspection (ILI) data needed to inform effective decision-making to mitigate a potential loss of pipeline containment (i.e., leak). Replacement with a new single pipeline, designed, manufactured and constructed to current standards that is ILI-capable can address this risk.

Project Timing & Execution Risks: Original in-service date is estimated to be Q3 2024. Overall project schedule is 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	Executing		

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

Spend Profile

Name	Net Base Capex O (CA)
Panhandle Line Replacement	$ 29,809,389

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ 1,619,900	$ 24,257,660	$ 3,392,719	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Report Generation Date: 5/30/2022

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
735972	**2023**	**10**
Investment Name		
PREP: NPS 36 looping to Comber Transmission		

Investment Description

Issue/Concern:
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 as early as the 2028 to 2029 winter season (construction beginning in 2028). These facilities are incremental to the Panhandle Regional Expansion Project and timing is dependent on the Panhandle System demands.

Assets:
Install approximately 12 km of NPS 36 pipeline from Richardson sideroad, looping the existing Panhandle NPS 20 pipeline to Comber Transmission Station (05E-403).

Recommended Alternative Description

Scope
To provide reliable, secure, and affordable natural gas supply to meet the growth in Design Day demand of the Panhandle System by installing approximately 12 km of NPS 36 pipeline from Richardson Sideroad, looping the existing Panhandle NPS 20 pipeline to Comber Transmission Station (05E-403).

Resources
This project will be internally managed by EGI staff. Construction work, such as well drilling and new pool piping installation, will be performed by contractors.

Solution Impact
Expansion of the Panhandle system will provide customers with increased access to diversity, reliability and security of supply of the Dawn Hub.

Project Timing & Execution Risks
This project starts in 2026 with its feasibility endorsed in Q2 2027. Construction will commence in 2028. The expected in-service date is Fall 2028.

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_02 - Chatham
	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	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Spend Profile - Recommende

Name	**Net Base Capex O (CA)**
PREP: NPS 36 looping to Comber Transmission	$ 70,000,000

Account Type	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Base CAPEX O	$ -	$ -	$ -	$ 7,000,000	$ 14,000,000	$ 42,000,000	$ 7,000,000	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Report Generation Date: 5/30/2022

Appendix B – IRP

Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
Eastern	60 - Ottawa	Distribution Pipe	Fail	Dollar threshold	11794	A60: City Centre Complex - Ottawa	2023	$ 578,721									
Eastern	60 - Ottawa	Distribution Pipe	Fail	Dollar threshold	23126	Concord St Isolated Steel Replace with Main St PE, Ottawa	2023	$ 599,422									
Eastern	60 - Ottawa	Distribution Pipe	Fail	Dollar threshold	23190	VPM - 310 Cathcart St Header - Aldyl A	2031	$ 348,702									
Eastern	60 - Ottawa	Distribution Pipe	Fail	Dollar threshold	30334	Ann St - Eastern - Area 60 - 1100	2032	$ 1,452,021									
Eastern	60 - Ottawa	Distribution Pipe	Fail	Dollar threshold	30342	Carling Ave - Eastern - Area 60 - 1104	2031	$ 1,734,079									
Eastern	60 - Ottawa	Distribution Pipe	Fail	Dollar threshold	30343	Centre St - Eastern - Area 60 - 1085	2027	$ 1,108,906									
Eastern	60 - Ottawa	Distribution Pipe	Fail	Dollar threshold	30347	Elm St W - Eastern - Area 60 - 1726	2028	$ 978,033									
Eastern	60 - Ottawa	Distribution Pipe	Fail	Dollar threshold	30352	George St - Eastern - Area 60 - 1088	2027	$ 1,462,056									
Eastern	60 - Ottawa	Distribution Pipe	Fail	Dollar threshold	30358	Highgate Rd - Eastern - Area 60 - 1166	2030	$ 1,212,189									
Eastern	60 - Ottawa	Distribution Pipe	Fail	Dollar threshold	30376	Othello Ave - Eastern - Area 60 - 1096	2028	$ 1,212,878									
Eastern	60 - Ottawa	Distribution Pipe	Fail	Dollar threshold	30388	Stanley Ave - Eastern - Area 60 - 1069	2030	$ 1,515,708									
Eastern	60 - Ottawa	Distribution Pipe	Fail	Dollar threshold	102424	Relocation Program - Area 60*	2020	$ 13,287,715									
Eastern	60 - Ottawa	Distribution Pipe	Fail	Dollar threshold	501823	A60 1149 Shillington HDR Replacement	2023	$ 158,256									
Eastern	60 - Ottawa	Distribution Pipe	Fail	Dollar threshold	502861	Morrison THP Replacement	2023	$ 305,493									
Eastern	60 - Ottawa	Distribution Pipe	Fail	Dollar threshold	502862	Young St LP Replacement	2023	$ 1,240,657									
Eastern	60 - Ottawa	Distribution Pipe	Fail	Dollar threshold	734548	VSM-HWY 7 Dufferin St Perth	2024	$ 1,301,690									
Eastern	60 - Ottawa	Distribution Pipe	Fail	Dollar threshold	734590	Viewmount Dr Main Lowering	2031	$ 570,662									
Eastern	60 - Ottawa	Distribution Pipe	Fail	Emergent Safety	4665	Replacement Blanket - Area 60*		$ 12,572,770									
Eastern	60 - Ottawa	Distribution Pipe	Pass		4671	Anode Blanket - Area 60*	2020	$ 3,382,114	**Justification: The Corrosion Department conducts pipe-to-soil readings each year on EGI's steel pipelines. When a corrosion area is identified as having fallen below EGI's minimum specifications, an order for a anode installation is processed. The capital request is for 12 months.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Eastern	60 - Ottawa	Distribution Pipe	Pass		4767	AMP Fitting Replacement - Area 60*		$ 68,867,529	**AMP Fittings are a below grade transition fittings. The inserted portion of copper tubing can fail due to internal corrosion. In these cases leaks develop immediately downstream of the AMP Fitting.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Eastern	60 - Ottawa	Distribution Pipe	Pass		8198	LANCASTER GATE Station - Integrity Retrofit > 30% SMYS	2026	$ 1,856,497	**Funds to install launcher (station rebuild occurred in 2016; no provisions for launcher were included) on pipeline to allow for inline inspection are required. This will allow in-line inspection of the pipeline which is required as per the Pipeline Integrity Management Program. 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 inline 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 that are identified through the inspections.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Eastern	60 - Ottawa	Distribution Pipe	Pass		8262	VSM - Preston St - LP	2026	$ 3,224,565	**Vintage Steel Mains, Isolated Steel Mains General: Vintage Steel Replacement Program is a proactive replacement program to renew aging vintage steel pipe assets before reaching their end of life. Vintage steel mains have shown signs of declining health due to the cumulative effect 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 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.**								
Eastern	60 - Ottawa	Distribution Pipe	Pass		10288	St. Laurent Phase 4 - Lower Section (Plastic)	2025	$ 11,339,012	**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 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 is required - the NPS 12 St. Laurent Ottawa North line is 13.3 km 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**	Planned							
Eastern	60 - Ottawa	Distribution Pipe	Pass		10290	St. Laurent Phase 3 - Coventry/Cummings/St. Laurent (Plastic)	2024	$ 11,273,059	**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 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 is required - the NPS 12 St. Laurent Ottawa North line is 13.3 km 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 (and 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 km of plastic pipe was installed on**	Planned							

* in the Investment Name indicates a program item. Program items are unique as they represent numerous projects grouped together and budgeted in advance. This results in forecast spend appearing larger than it would at the project level and it also impacts the in-service dates

Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
Eastern	60 - Ottawa	Distribution Pipe	Pass		10292	St. Laurent Phase 3 - Montreal to Rockcliffe (Plastic)	2024	$ 11,877,934	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 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: An inability to determine leaks due to the close proximity of the NPS 12 470 psi system is a concern. Cathodic protection was not installed until the early 1970s. Approximately 429 services are off this network. Full replacement of main comprising Network 6584 is required - the NPS 12 St. Laurent Ottawa North line is 13.3 km 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 (and does not include the crossing at the Rideau River to Station #61171A).	Planned							
Eastern	60 - Ottawa	Distribution Pipe	Pass		10293	St. Laurent Phase 3 - North/South (NPS12/16 Steel)	2024	$ 59,372,892	The NPS 12 St Laurent Pipeline requires replacement due to various pipeline conditions associated with the 1970 vintage steel mains including poor coating, unknown compression coupling fittings, reduced depth of cover, corrosion induced by declining cathodic protection. Replacing the main will ensure continued operation of EGI's gas distribution system, and will mitigate safety risks to employees, contractors, and general public. This project will install 6.5 km NPS 12 Steel Gas Main, 2.4 km NPS 16 Steel Gas Main, 5.1 km Plastic Gas Main and relay all XHP services to the new plastic gas main.	Planned							
Eastern	60 - Ottawa	Distribution Pipe	Pass		10294	St. Laurent Phase 4 - East/West (NPS12 Steel)	2025	$ 24,233,805	The NPS 12 St Laurent Pipeline requires replacement due to various pipeline conditions associated with the 1970 vintage steel mains including poor coating, unknown compression coupling fittings, reduced depth of cover, corrosion induced by declining cathodic protection. Replacing the main will ensure continued operation of EGI's gas distribution system, and will mitigate safety risks to employees, contractors, and general public. This project will install 3.1 km NPS 12 Steel Gas Main, Install 3.2 km Plastic Gas Main and relay all XHP services to the new plastic gas main	Planned							
Eastern	60 - Ottawa	Distribution Pipe	Pass		13609	Service Relay Blanket - Area 60*	2020	$ 52,687,565	General: 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.	Planned							
Eastern	60 - Ottawa	Distribution Pipe	Pass		30330	2nd Ave - Eastern - Area 60 - 1197	2028	$ 4,087,217	2nd Ave. - Eastern - Area 60 - 1197 Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.	Planned							
Eastern	60 - Ottawa	Distribution Pipe	Pass		30331	3rd Ave - Eastern - Area 60 - 1226	2030	$ 3,232,112	3rd Ave. - Eastern - Area 60 - 1226 Vintage steel pipes exhibit increased failures as they age, as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.	Planned							
Eastern	60 - Ottawa	Distribution Pipe	Pass		30332	Adelaide St - Eastern - Area 60 - 1218	2031	$ 2,158,470	Adelaide St. - Eastern - Area 60 - 1218 Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.	Planned							
Eastern	60 - Ottawa	Distribution Pipe	Pass		30333	Ainsley Dr - Eastern - Area 60 - 1723	2027	$ 2,128,900	Ainsley Dr - Eastern - Area 60 - 1723 Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization. Comments: Remove 8 m of mains from project due to overlap (updated as per regional feedback).	Planned							
Eastern	60 - Ottawa	Distribution Pipe	Pass		30338	Beckwith St N - Eastern - Area 60 - 1198	2032	$ 2,688,181	Beckwith St. N. - Eastern - Area 60 - 1198 Vintage steel pipes exhibit increased failures as they age, as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.	Planned							
Eastern	60 - Ottawa	Distribution Pipe	Pass		30339	Bell St - Eastern - Area 60 - 1052	2032	$ 2,274,693	Bell St. - Eastern - Area 60 - 1052 Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization. Comments: No timing comment was provided.	Complete	Fail	NPS 2, cannot downsize or retire					

* in the Investment Name indicates a program item. Program items are unique as they represent numerous projects grouped together and budgeted in advance. This results in forecast spend appearing larger than it would at the project level and it also impacts the in-service dates

Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
Eastern	**60 - Ottawa**	Distribution Pipe	**Pass**		**30340**	Borthwick Ave - Eastern - Area 60 - 1139	**2031**	$ 3,192,788	**Borthwick Ave. (moratorium is until 2025) - Eastern - Area 60 - 1139** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: Road work was completed in 2020. Road restrictions will be in place for a long time. The 2025 execution date is based on region's comment.**	Planned							
Eastern	**60 - Ottawa**	Distribution Pipe	**Pass**		**30341**	Brock St - Eastern - Area 60 - 1485	**2032**	$ 3,472,215	**Brock St. - Eastern - Area 60 - 1485** **Vintage steel pipes exhibit increased failures as they age, as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Complete	**Fail**	NPS 2, cannot downsize or retire					
Eastern	**60 - Ottawa**	Distribution Pipe	**Pass**		**30345**	Drummond St W - Eastern - Area 60 - 1142	**2028**	$ 2,470,450	**Drummond St. W. - Eastern - Area 60 - 1142** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
Eastern	**60 - Ottawa**	Distribution Pipe	**Pass**		**30346**	Elm St E - Eastern - Area 60 - 1147	**2032**	$ 2,426,470	**Elm St. E. - Eastern - Area 60 - 1147** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: There are possible road restrictions on County Rd 29 and 15.**	Planned							
Eastern	**60 - Ottawa**	Distribution Pipe	**Pass**		**30348**	Elmsley St N - Eastern - Area 60 - 1725	**2032**	$ 1,861,690	**Elmsley St. N. - Eastern - Area 60 - 1725** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: A possible permit may be required due to proximity to rail yard. A possible Conservation Authority (CA) permit may be required due to historic buildings. Estimate includes 46 m of PE replacement but the number of services may not be correct;**	Planned							
Eastern	**60 - Ottawa**	Distribution Pipe	**Pass**		**30349**	Emily St - Eastern - Area 60 - 1101	**2031**	$ 2,287,957	**Emily St. - Eastern - Area 60 - 1101** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: There are possible road restrictions.**	Planned							
Eastern	**60 - Ottawa**	Distribution Pipe	**Pass**		**30350**	First Ave - Eastern - Area 60 - 1175	**2031**	$ 3,442,055	**First Ave. - Eastern - Area 60 - 1175** **Vintage steel pipes exhibit increased failures as they age, as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
Eastern	**60 - Ottawa**	Distribution Pipe	**Pass**		**30351**	Flora St - Eastern - Area 60 - 1151	**2032**	$ 2,528,992	**Flora St - Eastern - Area 60 - 1151** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: Possible road work to occur along High St.**	Planned							
Eastern	**60 - Ottawa**	Distribution Pipe	**Pass**		**30354**	Grant St - Eastern - Area 60 - 1098	**2032**	$ 2,665,699	**Grant St. - Eastern - Area 60 - 1098** **Vintage steel pipes exhibit increased failures as they age, as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: Possible CA permit may be required due to proximity to Tay River.**	Planned							
Eastern	**60 - Ottawa**	Distribution Pipe	**Pass**		**30356**	Havelock St - Eastern - Area 60 - 1215	**2031**	$ 4,243,311	**Havelock St. - Eastern - Area 60 - 1215** **Vintage steel pipes exhibit increased failures as they age, as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							

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Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
Eastern	**60 - Ottawa**	Distribution Pipe	**Pass**		**30357**	Herriott St - Eastern - Area 60 - 1089	**2032**	$ 1,848,715	**Herriott St. - Eastern - Area 60 - 1089** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: There are possible road restrictions on Moffatt Asphalt Overlay.**	Planned							
Eastern	**60 - Ottawa**	Distribution Pipe	**Pass**		**30359**	Irene Cres - Eastern - Area 60 - 1141	**2028**	$ 2,919,753	**Irene Cres. - Eastern - Area 60 - 1141** **Vintage steel pipes exhibit increased failures as they age, as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
Eastern	**60 - Ottawa**	Distribution Pipe	**Pass**		**30360**	James St - Eastern - Area 60 - 1112	**2029**	$ 2,617,144	**James St. - Eastern - Area 60 - 1112** **Vintage steel pipes exhibit increased failures as they age, as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: CR 34 Major Rd. into Quebec might require an MTO permit. Main St. is already dual-mained and side streets could be considered. Possible CA permit may be required due to proximity to Ottawa River.**	Planned							
Eastern	**60 - Ottawa**	Distribution Pipe	**Pass**		**30361**	James St W - Eastern - Area 60 - 1184	**2031**	$ 2,941,172	**James St. W. - Eastern - Area 60 - 1184** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Complete	**Fail**	NPS 2, cannot downsize or retire					
Eastern	**60 - Ottawa**	Distribution Pipe	**Pass**		**30363**	Lake Ave E - Eastern - Area 60 - 1145	**2032**	$ 4,172,549	**Lake Ave. E. - Eastern - Area 60 - 1145** **Vintage steel pipes exhibit increased failures as they age, as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
Eastern	**60 - Ottawa**	Distribution Pipe	**Pass**		**30364**	LePage Ave - Eastern - Area 60 - 1214	**2029**	$ 3,885,028	**LePage Ave. (execute by 2025 - paving proposed between 2022 - 2025) - Eastern - Area 60 - 1214** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: Some road and sewer work was done in 2021, and paving is proposed between 2022 and 2025 - updated to reflect region's comments.**	Planned							
Eastern	**60 - Ottawa**	Distribution Pipe	**Pass**		**30365**	Madawaska St - Eastern - Area 60 - 1072	**2030**	$ 3,169,523	**Madawaska St - Eastern - Area 60 - 1072** **Vintage steel pipes exhibit increased failures as they age, as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
Eastern	**60 - Ottawa**	Distribution Pipe	**Pass**		**30366**	Main St E - Eastern - Area 60 - 1172	**2031**	$ 3,168,096	**Main St. E. - Eastern - Area 60 - 1172** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: There is 83 m of 2-inch steel being replaced. Downtown road is likely to have time restrictions.**	Complete	**Fail**	NPS 2, cannot downsize or retire					
Eastern	**60 - Ottawa**	Distribution Pipe	**Pass**		**30367**	McCann St - Eastern - Area 60 - 1160	**2029**	$ 4,429,658	**McCann St. - Eastern - Area 60 - 1160** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
Eastern	**60 - Ottawa**	Distribution Pipe	**Pass**		**30368**	McGonigal St E - Eastern - Area 60 - 1041	**2032**	$ 2,640,734	**McGonigal St. E. - Eastern - Area 60 - 1041** **Vintage steel pipes exhibit increased failures as they age, as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							

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Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
Eastern	60 - Ottawa	Distribution Pipe	Pass		30369	Moffatt St - Eastern - Area 60 - 1195	2032	$ 3,302,942	**Moffatt St. - Eastern - Area 60 - 1195** **Vintage steel pipes exhibit increased failures as they age, as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: Townline Rd. and Bridge St. are main roads. There are rectifier-protected areas. Main on Townline Rd. may have to stay steel.**	Planned							
Eastern	60 - Ottawa	Distribution Pipe	Pass		30370	Montgomery Pl - Eastern - Area 60 - 1228	2030	$ 3,228,256	**Montgomery Pl. - Eastern - Area 60 - 1228** **Vintage steel pipes exhibit increased failures as they age, as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
Eastern	60 - Ottawa	Distribution Pipe	Pass		30372	North St - Eastern - Area 60 - 1087	2029	$ 2,613,031	**North St - Eastern - Area 60 - 1087** **Vintage steel pipes exhibit increased failures as they age, as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
Eastern	60 - Ottawa	Distribution Pipe	Pass		30373	Oak St - Eastern - Area 60 - 1133	2029	$ 2,720,235	**Oak St. - Eastern - Area 60 - 1133** **Vintage steel pipes exhibit increased failures as they age, as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Complete	**Fail**	NPS 2, cannot downsize or retire					
Eastern	60 - Ottawa	Distribution Pipe	Pass		30378	Prince Albert St - Eastern - Area 60 - 1099	2031	$ 2,866,490	**Prince Albert St. - Eastern - Area 60 - 1099** **Vintage steel pipes exhibit increased failures as they age, as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
Eastern	60 - Ottawa	Distribution Pipe	Pass		30379	Queen Mary St - Eastern - Area 60 - 1103	2030	$ 3,155,878	**Queen Mary St. - Eastern - Area 60 - 1103** **Vintage steel pipes exhibit increased failures as they age, as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
Eastern	60 - Ottawa	Distribution Pipe	Pass		30380	Queen St N - Eastern - Area 60 - 1158	2030	$ 3,743,198	**Queen St. N. - Eastern - Area 60 - 1158** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
Eastern	60 - Ottawa	Distribution Pipe	Pass		30384	Rochester St - Eastern - Area 60 - 1222	2031	$ 2,794,057	**Rochester St. - Eastern - Area 60 - 1222** **Vintage steel pipes exhibit increased failures as they age, as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: There is the potential for road restrictions due to congested area.**	Planned							
Eastern	60 - Ottawa	Distribution Pipe	Pass		30385	Sarah St - Eastern - Area 60 - 1188	2032	$ 2,805,417	**Sarah St. - Eastern - Area 60 - 1188** **Vintage steel pipes exhibit increased failures as they age, as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
Eastern	60 - Ottawa	Distribution Pipe	Pass		30387	Spring St - Eastern - Area 60 - 1047	2031	$ 2,097,135	**Spring St. - Eastern - Area 60 - 1047** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: There are major roads where there could be difficulty with traffic management. CA permit is required due to proximity to river.**	Planned							
Eastern	60 - Ottawa	Distribution Pipe	Pass		30389	Summerville Ave - Eastern - Area 60 - 1484	2030	$ 3,502,575	**Summerville Ave. - Eastern - Area 60 - 1484** **Vintage steel pipes exhibit increased failures as they age, as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							

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Eastern	**60 - Ottawa**	Distribution Pipe	**Pass**		**30390**	Trenton Ave - Eastern - Area 60 - 1181	**2032**	$ 2,285,032	**Trenton Ave. - Eastern - Area 60 - 1181** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
Eastern	**60 - Ottawa**	Distribution Pipe	**Pass**		**30391**	Victoria St - Eastern - Area 60 - 1138	**2032**	$ 2,566,545	**Victoria St - Eastern - Area 60 - 1138** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: There is potential for road restrictions due to congested area.**	Planned							
Eastern	**60 - Ottawa**	Distribution Pipe	**Pass**		**30393**	William St - Eastern - Area 60 - 1092	**2031**	$ 2,157,149	**William St. - Eastern - Area 60 - 1092** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
Eastern	**60 - Ottawa**	Distribution Pipe	**Pass**		**30394**	Wilson St E - Eastern - Area 60 - 1094	**2029**	$ 2,294,786	**Wilson St. E. - Eastern - Area 60 - 1094** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Complete	**Fail**	NPS 2, cannot downsize or retire					
Eastern	**60 - Ottawa**	Distribution Pipe	**Pass**		**30395**	Woodside Dr - Eastern - Area 60 - 1178	**2030**	$ 3,526,589	**Woodside Dr. - Eastern - Area 60 - 1178** **Vintage steel pipes exhibit increased failures as they age, as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
Eastern	**60 - Ottawa**	Distribution Pipe	**Pass**		**101343**	A60: Sparks St, Ottawa, Replacement	**2024**	$ 11,808,967	**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. Replacement work is timed ahead of planned third-party road construction work along Sparks and Albert Street that could create third-party damage to these components and result in loss of containment. It will also provide an opportunity to coordinate development and design work with the Sparks Business Improvement Area (BIA) along with planned utility work on Albert Street.** **Assets: Approximately 1,100 m of NPS 12 intermediate pressure (IP) steel pipe on Albert Street, 900 m of NPS 4 IP Polyethylene (PE) pipe on Sparks Street, and 175 m of NPS 4 PE pipe from Lyons to Wellington.** **Related Programs: Not applicable.**	Planned							
Eastern	**60 - Ottawa**	Distribution Stations	**Fail**	Dollar threshold	**1012**	LEEDS GATE	**2026**	$ 1,046,196									
Eastern	**60 - Ottawa**	Distribution Stations	**Fail**	Dollar threshold	**7750**	HALEY GATE	**2025**	$ 530,592									
Eastern	**60 - Ottawa**	Distribution Stations	**Fail**	Dollar threshold	**7755**	PETAWAWA GATE	**2026**	$ 455,649									
Eastern	**60 - Ottawa**	Distribution Stations	**Fail**	Dollar threshold	**23766**	ST. PAUL & SANDFIELD DISTRICT (ALEXANDRIA)	**2027**	$ 305,290									
Eastern	**60 - Ottawa**	Distribution Stations	**Fail**	Dollar threshold	**101151**	6B758A - EAGLESON & HAZELDEAN DISTRICT	**2023**	$ 196,825									
Eastern	**60 - Ottawa**	Distribution Stations	**Fail**	Dollar threshold	**101152**	6B562A - CAMPEAU & TERON DISTRICT HP (O.P.P.)	**2023**	$ 196,825									
Eastern	**60 - Ottawa**	Distribution Stations	**Fail**	Dollar threshold	**101153**	6B435A - CORKSTOWN & WESTDALE DISTRICT	**2024**	$ 202,265									
Eastern	**60 - Ottawa**	Distribution Stations	**Fail**	Dollar threshold	**101154**	61128A - CAMPBELL & MCNABB DISTRICT	**2024**	$ 202,265									
Eastern	**60 - Ottawa**	Distribution Stations	**Fail**	Dollar threshold	**501534**	Kemptville Gate Station - Electrical	**2023**	$ 249,382									
Eastern	**60 - Ottawa**	Distribution Stations	**Fail**	Dollar threshold	**501535**	Elizabethtown/Bethel - Electrical	**2027**	$ 416,883									
Eastern	**60 - Ottawa**	Distribution Stations	**Fail**	Dollar threshold	**735164**	6B631A MCCARTHY DR AND HUNT CLUB RD	**2023**	$ 196,825									
Eastern	**60 - Ottawa**	Distribution Stations	**Fail**	Dollar threshold	**735165**	6B602A STARTOP DISTRICT XHP	**2023**	$ 196,825									
Eastern	**60 - Ottawa**	Distribution Stations	**Fail**	Dollar threshold	**735167**	61061A PEMBROKE W. DISTRICT	**2023**	$ 196,825									
Eastern	**60 - Ottawa**	Distribution Stations	**Pass**		**3455**	Harmer District Station	**2028**	$ 5,271,812	**Issue/Concern: EGI has a high pressure (HP) to intermediate pressure (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 inline inspection of the Vital NPS 12 (Network 6582) and additional space is required for a receiver.** **Assets: Station# 6B005A** **Related Program(s): N/A**	Planned							

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Eastern	**60 - Ottawa**	Distribution Stations	**Pass**		**3608**	BROCKVILLE GATE	**2025**	$ 2,620,194	**Brockville Gate Station is located on EGI-owned property approximately 5 km from the town of Brockville, Ontario. This station accepts natural gas from TC Energy and provides supply to two separate XHP networks. Station components include measurement, gas preheat system, pressure regulation, odourant injection and a telemetry system. This station supplies natural gas to approximately 19,463 customers in Brockville region. The following issues have been identified at this station:** **Pipes, Valves & Others: The existing valves at this site have experienced issues in performance and operation of the valves. Valve maintenance has been unable to remediate the problem and the valves have deteriorated to the point where the reliability is no longer acceptable. All valves will have to be replaced. The inlet of the regulator runs is a challenge every year.** **Heating: The boiler system was replaced in 2019. However, the glycol tank and heat exchanger will need to be replaced and relocated to meet Electrical Safety Authority (ESA) requirements. Residual glycol impacts are to be evaluated and removed as required, as a result of glycol release that was reported from a boiler inside the Boiler building.** **Pressure Control: The regulator station has boot-style regulators posing an undesired higher risk and high associated ongoing maintenance costs. Engineering has identified that boot-style regulators operating as both monitor and operating regulators is unacceptable. The regulator runs will have to be rebuilt.** **Odourization: The odourant system was installed in 2000. A new Odourant building will have to be installed to ensure adequate containment in the event of a leak. The injection pumps are located in the regulator room and will have to be relocated into the Odourant building to meet current standards.** **Telemetry and Electrical: The size of the Remote Terminal Unit (RTU) building is not an issue but the leaky roof is. This building not only houses the RTU but also the St. Lawrence Control Centre (CC) (this is the gas control hub for Leeds, Brockville, Bethel, St. Lawrence, Summerstown and Lancaster Gate stations, as well as International Bridge CDN and USA, and Lisgar). The transfer switch, main panel, and junction box are located in the old RTU room, which is attached to the instrumentation room, but does not violate the Electrical code. Boilers were recently replaced and can be reused as well as the inlet/outlet and tank pressure transmitters. New temperature transmitters and a new tank level gauge are needed. The ultrasonic electronics should be upgraded. The main** [illegible]	Planned							
Eastern	**60 - Ottawa**	Distribution Stations	**Pass**		**3622**	SUMMERSTOWN GATE	**2026**	$ 3,582,565	**Summerstown Gate Station is located on EGI-owned property of approximately 1,000 m2 fenced compound in South Glengarry Township, Ontario, approximately 16 km from Cornwall, Ontario, within a rural area. This station accepts natural gas from TC Energy and provides supply to an XHP network, through components within the measurement system, pressure control system, heating system, odourant system, and telemetry system. This station feeds 265 customers. The following issues have been identified at this station:** **Valves & Piping: The existing valves at this site have experienced issues in performance and operation of the valves. Maintenance has been performed to attempt to remediate the valves; however, the valves have deteriorated to the point where the reliability is no longer acceptable. The existing inlet and bypass valves are flange by flange and have experienced leaks through these flanges. Flanged valves on the station inlets are more prone to leaks and more difficult to repair.** **Odourization: The odourant system was installed in 1998. The current configuration of the odourant system does not ensure adequate containment of the odourant product in the event of a leak and does not meet the current engineering standards and approvals.** **Telemetry & Electrical: The existing electrical system does not meet current EGI electrical installation standards. This poses a potential electrical hazard and faulty wiring may result in lost communications.** **Tower: Tower is to be removed as it is not required for SCADA communications.**	Planned							
Eastern	**60 - Ottawa**	Distribution Stations	**Pass**		**7751**	KEMPTVILLE GATE	**2025**	$ 5,739,416	**Kemptville Gate Station is located on EGI-owned property of approximately 2,825 m2 fenced compound in the Municipality of North Grenville, Ontario, approximately 37 km south of Ottawa, within a rural area. This station accepts natural gas from TC Energy and provides supply to XHP networks, through components within the Measurement system, Pressure Control system , Heating system, Odourant system, and Telemetry system. This station supplies natural gas to approximately 3,256 customers in the Kemptville area. The following issues have been identified at this station:** **Pipe, Valves & Others: The existing valves at this site have experienced issues in performance and operation. Maintenance has been performed to attempt to remediate the valves; however, the valves have deteriorated to the point where the reliability is no longer acceptable.** **Heating: The existing boilers at this site are 22 years old and have reached end of life based on condition review and performance.** **Pressure Control: The Regulation system is installed within a building currently in disrepair with several leaks. The operator and monitor regulators are both double-boot style regulators and are both susceptible to boot failure should they be exposed to significant debris in the system. Repairs have been made where possible but the building continues to deteriorate. Also, the working space inside the building produces an ergonomic/safety risk to EGI employees. This will require addition of filtration or regulation replacement. Furthermore, a new building will be required to address safety/ergonomic issues at the station.** **Odourization: The building has containment but does not meet current standards. There are no issues with the current system.** **Telemetry & Electrical: The Telemetry and Electrical systems do not meet current EGI standards, do not contain backup power supply in the event of power loss, and are approaching end of useful life. The existing Remote Terminal Unit (RTU) is obsolete and is required to be upgraded to current standards along with new communications equipment in order to mitigate cybersecurity threats.**	Planned							
Eastern	**60 - Ottawa**	Growth	**Pass**		**3758**	Area 60 - Apartment Ensuite - New Construction*		$ 101,629	**Vertical Subdivision - A multiple unit residential building where each suite is individually metered. Issue/Concern: EGI is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers.**	Planned							
Eastern	**60 - Ottawa**	Growth	**Pass**		**3759**	Area 60 - Apartment Traditional - New Construction*		$ 402,687	**Apartment - An apartment customer is a multi-residential dwelling containing more than six units that is bulk-metered Issue/ Concern: EGI is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers.**	Planned							
Eastern	**60 - Ottawa**	Growth	**Pass**		**1024**	NW 6581 Ottawa Reinforcement Phase 2 SRP	**2032**	$ 71,584,955	**Issue/Concern/Opportunity: 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. An upstream flow constraint has been identified 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 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 were approximately 193,553 customers on the associated networks as of 2016.** **Assets: Existing NPS 12 HP Pipe** **Related Program: Not applicable**	In Progress							

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Eastern	**60 - Ottawa**	Growth	**Pass**		**3761**	Area 60 - Commercial - New Construction*		$ 25,177,089	**Issue/Concern: Commercial New Construction refers to a customer intending to run a commercial business in a newly-constructed building and intending to using natural gas to meet energy needs** **Issue/Concern: EGI is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGI will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGI develops a customer additions forecast using a number of information sources: - Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities - Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates - Projections developed by external consultants specializing in population growth forecasting - Municipal long-term plans: EGI extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report. EGI reviews the following when determining feasibility: - The number of potential new customers - The consumption of natural gas by new customers - The cost of extending the gas main The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGI determines the CIAC amount and communicate with the applicant(s) in writing. Generally, there are three components of capital investments needed to support customer addition requirements: - Installation costs related to mains, services, and meters - Material costs related to mains, services and meters - Costs related to measurement and regulation equipment required to support customer growth.** **Assets: All applicable assets.** **Related Program: N/A**	Planned							
Eastern	**60 - Ottawa**	Growth	**Pass**		**3762**	Area 60 - Industrial - New Construction*		$ 34,475,558	**Issue/Concern: Industrial New Construction refers to a customer intending to run an industrial manufacturing business in a newly-built facility and intending to use natural gas.** **Issue/Concern: EGI is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGI will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGI develops a customer additions forecast using a number of information sources: - Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities - Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates - Projections developed by external consultants specializing in population growth forecasting - Municipal long-term plans: EGI extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report. EGI reviews the following when determining feasibility: - The number of potential new customers - The consumption of natural gas by new customers - The cost of extending the gas main The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGI determines the CIAC amount and communicate with the applicant(s) in writing. Generally, there are three components of capital investments needed to support customer addition requirements: - Installation costs related to mains, services, and meters - Material costs related to mains, services and meters - Costs related to measurement and regulation equipment required to support customer growth.** **Assets: All applicable assets.** **Related Program: N/A**	Planned							
Eastern	**60 - Ottawa**	Growth	**Pass**		**3764**	Area 60 - Residential - New Construction*		$ 237,751,447	**Issue/Concern: Residential New Construction refers to a new residential construction development of detached single homes constructed by the builder for domestic purposes.** **Issue/Concern: EGI is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGI will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGI develops a customer additions forecast using a number of information sources: - Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities - Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates - Projections developed by external consultants specializing in population growth forecasting - Municipal long-term plans: EGI extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report. EGI reviews the following when determining feasibility: - The number of potential new customers - The consumption of natural gas by new customers - The cost of extending the gas main The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGI determines the CIAC amount and communicate with the applicant(s) in writing. Generally, there are three components of capital investments needed to support customer addition requirements: - Installation costs related to mains, services, and meters - Material costs related to mains, services and meters - Costs related to measurement and regulation equipment required to support customer growth.** **Assets: All applicable assets.** **Related Program: N/A**	Planned							

* in the Investment Name indicates a program item. Program items are unique as they represent numerous projects grouped together and budgeted in advance. This results in forecast spend appearing larger than it would at the project level and it also impacts the in-service dates

Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
Eastern	60 - Ottawa	Growth	Pass		3765	Area 60 - Residential - Replacement*		$ 169,789,900	Issue/Concern: Residential Replacement refers to a residential replacement customer using a fuel other than natural gas for domestic purposes and is converting to natural gas. Issue/Concern: EGI is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGI will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGI develops a customer additions forecast using a number of information sources: - Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities - Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates - Projections developed by external consultants specializing in population growth forecasting - Municipal long-term plans: EGI extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report. EGI reviews the following when determining feasibility: - The number of potential new customers - The consumption of natural gas by new customers - The cost of extending the gas main The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGI determines the CIAC amount and communicate with the applicant(s) in writing. Generally, there are three components of capital investments needed to support customer addition requirements: - Installation costs related to mains, services, and meters - Material costs related to mains, services and meters - Costs related to measurement and regulation equipment required to support customer growth. Assets: All applicable assets. Related Program: N/A	Planned							
Eastern	60 - Ottawa	Growth	Pass		7743	NW 6587 L'Original Reinforcement SRP	2025	$ 1,883,892	Victoria St - Eastern - Area 60 - 1138 Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization. Comments: There is potential for road restrictions due to congested area. 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: This reinforcement is to add capacity within legacy Enbridge Gas Distribution's pipe network to: o Satisfy the current contractually allowable demand of the Large Volume Contract (LVC) customer Ivaco Rolling Mills, which is 6,800 m3/h o Support customer growth of the downstream High Pressure Polyethylene (HPPE) network This geographic area sits at the eastern tail end of XHP network 6587, which is fed exclusively by Lancaster gate to the southeast. • Pressure Issue/Concern : The minimum system pressure was forecasted to be infeasible by 2020. • Customer Growth Issue/Concern: As of 2017, there are 2,039 customers on this network. Without reinforcement, a forecasted 24 customers may not be able to be added. • Risk If Not Completed: System risk without the reinforcement	Planned							
Eastern	60 - Ottawa	Growth	Pass		102119	Brockville Gate Extension	2025	$ 3,170,327	Issue/Concern/Opportunity: Area 60 - the Maitland and Brockville regions are currently served by two Gate Stations (i.e., Brockville and Bethel). The Bethel Gate requires a rebuild to maintain safe and reliable operations; and there is an opportunity to add customers in the region if the network has more capacity. The preferred option is to build a lateral connected to the existing Brockville Network extending to the current Bethel Gate site; a district station would be required along with 3,500 m of pipe. Sixty-two potential customers have been identified along this route. A secondary option is to rebuild the Bethel Gate which will ensure safe and reliable operations but will not allow for the opportunity to connect potential new customers. Justification: Bethel Gate is scheduled for a rebuild in 2023 and the pipeline reinforcement is a second option which has added benefits of customer additions and lower future maintenance costs. Assets: Bethel Gate Station Related Program: Not applicable	Planned							
Eastern	60 - Ottawa	Growth	Pass		501824	Huntmar Drive Reinforcement	2023	$ 3,542,336	Reinforcement required to maintain the gas capacity in the Kanata West area for multiple developments proposed and being built currently in the area. Scope: Install approx. 2.8km of NPS 6 XHP Steel gas main from NPS 12 XHP at Huntmar & Hazeldean going north on Huntmar to Palladium Dr, then install a XHP-HP station at 620 Palladium Drive with its outlet tied in to the existing NPS 6 HP Steel gas main on Palladium Drive. There are no station projects directly linked to this reinforcement project.	Planned							
Eastern	60 - Ottawa	Growth	Pass		736679	NW 6544 Sherwood Drive Crossing SRP	2024	$ 99,947	Issue/Concern/Opportunity: Reinforcement required to resolve low pressure points that are below the minimum system pressure. Pressures are forecasted to be below the system minimum by 2024 Assets: 30m of NPS 2 PE IP road crossing at Sherwood Dr. and Old Irving Related Program: Not applicable	Planned							
Eastern	60 - Ottawa	Growth	Pass		736680	NW 6429 Rockland IP Reinforcement SRP	2024	$ 233,211	Issue/Concern/Opportunity: Increase pressures that are below new system min in multiple locations. Pressure less then the 20 psi minimum in multiple locations on the network. Reinforcements are required to bring the system within standards. The system is single-fed and is located at the tail end of the XHP 6580 network that is primarily fed by the Ottawa Gate Station. Assets: Install 30m of 1 1/4" PE IP on Du Chateau Ave from Woods St to 30 m S of Woods St Install 55m of 2" PE IP on Lalonde St from Laurier St to 55 m N of Laurier St Install 100m of 2" PE IP On Notre Dame St from Laurier St to Alma St Related Program: Not applicable	Planned							
Eastern	60 - Ottawa	Growth	Pass		736682	NW 6544 Bank St. Reinforcement SRP	2024	$ 174,908	Issue/Concern/Opportunity: Reinforcement required to resolve operational issues and bring pressures above the 20 psig minimum sytem pressures and support future growth. The system being reinforced is in Ottawa central with high potential for growth. Current system pressures are below the minimum system pressures. Network is double-fed by Ottawa Gate and Richmond Gate Station Assets: 90m NPS 2 PE IP on Bank St. from Ardington Ave to Flora St. Related Program: Not applicable	Planned							
Eastern	60 - Ottawa	Growth	Pass		736758	NW 6466 Carp Pressure Increase SRP	2024	$ 25,628	Issue/Concern/Opportunity: Reinforcement involves an in-class pressure increase to resolve operational issues and pressure low points on the network below the minimum system and support growth. The network being reinforced is single-fed and sits on the tail end of the 6583 high pressure network. Pressures are forecasted to go below the minimum system pressure by 2024. All pipes were installed after 1994. Assets:New district station replacing station near the intersection of Carp Rd. and March Rd. (Station ID: 526053). Related Investments: Not applicable	Planned							

* in the Investment Name indicates a program item. Program items are unique as they represent numerous projects grouped together and budgeted in advance. This results in forecast spend appearing larger than it would at the project level and it also impacts the in-service dates

Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
Eastern	**60 - Ottawa**	Growth	**Pass**		**736759**	NW 6462 Russell Pressure Increase and Reinforcement SRP	**2024**	$ 25,628	**Issue/Concern/Opportunity: Reinforcement involves an in-class pressure increase from 45 psi to 55 psi to resolve operational issues and pressure lowpoints on the network below the 20 psig minimum system pressure and to support growth. All pipes installed after 1994. The two adjacent networks are not currently connected, and a future reinforcement will connect them. Eastern network contains ~42 km PE IP to be increased. Western network contains ~5.8 km PE IP to be increased. Station flows are 2022 and 2032 from previous project timing. The network is single-fed exclusively by Metcalfe Gate Station Assets: -Increase pressures at existing district stations on the intersection of Old Towne Ave. and Craig St. (Station ID 3180568) -Increase pressures at existing district station on the intersection of Castor St. and Warner St. (Station ID: 526844) -160 m of NPS 2 PE IP pipe on Craig St from Olde Towne Ave to Forced Rd Related Investments: Not applicable**	Planned							
Eastern	**60 - Ottawa**	Growth	**Pass**		**736760**	NW 6652 Bunker Rd. Reinforcement SRP	**2028**	$ 134,332	**Issue/Concern/Opportunity: Reinforcement required to resolve operational issues and pressure lowpoints on the network below the 20 psig minimum system pressure and support growth. Network sits near the end of the XHP 6581 NW that is fed by Ottawa Gate and Richmond Gate Station. Pressure are forecasted to be below the minimum system pressures by 2027 Assets: -240 m NPS 2 PE IP on Bunker Rd. from Marina Dr. to 240m W of Marina Dr. Related Program: Not applicable**	Planned							
Eastern	**60 - Ottawa**	Growth	**Pass**		**736761**	NW 6579 Kemptville Reinforcement SRP	**2026**	$ 533,940	**Issue/Concern/Opportunity:Reinforcement required to resolve operational issues and pressure lowpoints on the network below the 20 psig minimum system and support growth. Estimated 2 weeks of Aecon and 2 days for TFS. Also estimating to buy district station in 2025. System pressures are forecasted to be below the minimum system pressure by 2026. Network is single-fed exlusively by Kemptville Gate Station Assets: - 50 m NPS 2 SC XHP road crossing at Country Rd. 43 and Rideau St. - 40 m NPS 2 PE IP road crossing at Country road 43 and Rideau St. -20 m NPS 1 1/4 PE IP road crossing at Thomas St. and Asa. St. -New district station near the intersection of Country Rd. 43 and Rideau St. to feed the Kemptville community Related Program: Not applicable**	In Progress							
Eastern	**60 - Ottawa**	Growth	**Pass**		**736762**	NW 6463 Embrun Reinforcement SRP	**2026**	$ 424,996	**Issue/Concern/Opportunity: Reinforcement to support imminent and significant growth in the area. Network is currently operating under 20psi Assets: NPS 4 PE IP along the south side of Ste Therese Blvd in Embrun Related Program: Growth investment # 737580**	Planned							
Eastern	**60 - Ottawa**	Growth	**Pass**		**736763**	NW 6556 Des Paturages Rd Reinforcement SRP	**2029**	$ 124,644	**Issue/Concern/Opportunity: Reinforcement required to resolve operational issues and pressure lowpoints on the network below the 20 psig minimum system. The reinforcement will also support future growth. Network 6556 estimated to be below minimum system pressures by 2029. NW 6556 is situated near the tail end of the of the XHP network 6587 fed exclusively by Lancaster Gate Station and the community is located next to the LVC Ivaco Rolling Mills. A reinforcement has also been called for the 6587 NW (C55 ID#: 7743) to support both this community and meet the contractual demands of Ivaco Rolling Mills. Assets: 220m of NPS 2 PE IP Related Program: C55 ID: 7743**	Planned							
Eastern	**60 - Ottawa**	Growth	**Pass**		**736764**	NW 6518 Barrhaven Reinforcement SRP	**2028**	$ 35,822	**Issue/Concern/Opportunity: Reinforcement required to resolve operational issues and pressure lowpoints on the network below the 20 psig minimum system. The reinforcement will also support growth. Pressures are forecasted to be below 20 psig by 2028. The network supports a densely populated area that is fed by both Ottawa Gate Station and Richmond Gate Station Assets: -20 m NPS 1 1/4 PE IP -new district station at the intersection of Larkin Dr. and Fallowfield Rd. Related Program: Not applicable**	Planned							
Eastern	**60 - Ottawa**	Growth	**Pass**		**736766**	NW 6540 Stevenage Dr Reinforcement SRP	**2029**	$ 320,514	**Issue/Concern/Opportunity: Reinforcement required to resolve operational issues and pressure lowpoints on the network below the 20 psig minimum system and support growth. Pressures are forecasted to be below the minimum system pressure by 2029. The network supports the demand of LVC Ottawa Fibre L.P. The reinforcement will mitigate the system risk of not being able to satisfy the contractual demand of this LVC and the needs of potential future growth. Assets: 310 m of NPS 4 PE IP on Stevenage Rd. from Hawthorne Rd. to Overton Dr. Related Program: Not applicable**	Planned							
Eastern	**60 - Ottawa**	Growth	**Pass**		**736768**	NW 6414 Orville St Reinforcement SRP	**2030**	$ 45,851	**Issue/Concern/Opportunity: Reinforcement required to resolve operational issues and pressure lowpoints on the network below the 20 psig minimum system pressure and support growth. System pressures expected to be below minimum system pressures by 2030. Network supports a densely populated area in Ottawa. Assets:15m NPS 2 PE IP road crossing at Orville St. and Basswood Ave. Related Investments: Not applicable**	Planned							
Eastern	**60 - Ottawa**	Growth	**Pass**		**736769**	NW 6524 Quincy Ave. Reinforcement SRP	**2030**	$ 201,742	**Issue/Concern/Opportunity: Reinforcement required to resolve operational issues and pressure lowpoints on the network below the 20 psig minimum system and support system growth. System pressures are forecasted to be below the minimum system pressure by 2031. Reinforcement will support a highly populated area in central Ottawa. Assets: - 30 m of NPS 2 PE IP road crossing at Ogilvie Rd. and Quincy Ave. - 15 m of NPS 4 PE IP road crossing at Canoteck Rd. Related Program: Not applicable**	Planned							
Eastern	**60 - Ottawa**	Utilization	**Pass**		**13548**	MXGI Area 60*	**2019**	$ 56,558,621	**Meters: Meters are used to determine the gas consumption input of customer billing. The replacement program for meters is mandated by Measurement Canada. The program includes: testing, repair, and replacement requirements of meters and instruments. All verified meters are approved by Measurement Canada with an issuance of a certificate which identifies that the meter complies with Electricity and Gas Specification S-EG-02. The Company must ensure all measurement devices remain in compliance for annual audits by Measurement Canada. Measurement Canada specifies tolerances under which the meter must operate in the field. The Company must demonstrate that all aspects of its meter sampling, maintenance, and replacement comply with these criteria in order to be accredited by Measurement Canada to be an “Authorized Service Provider” and adhere to Measurement Canada’s accreditation standard S-A-01. Meters may also require exchange for issues such as: damages, leaks, customer billing issues. Regulation: Regulators are the last line of defense for over-pressure to the customer. The condition of regulation systems is determined by regulator performance, corrosion of piping and regulators, and adherence to installation specifications. Failure of the regulation system can cause pressured gas to enter the premise, resulting in failure of gas equipment, loss of containment, and potentially fire or explosion.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Eastern	**Div_22 - Kingston**	Distribution Pipe	**Fail**	Dollar threshold	**1289**	Thurlow Township Retrofit		$ 1,145,916									
Eastern	**Div_22 - Kingston**	Distribution Pipe	**Fail**	Dollar threshold	**48472**	KING: 22-21-043 Dist-Repl-Contractor Services*	**2020**	$ 4,510,485									
Eastern	**Div_22 - Kingston**	Distribution Pipe	**Fail**	Dollar threshold	**48477**	King: 22-YY-022 Mains Municipal*	**2020**	$ 7,517,485									
Eastern	**Div_22 - Kingston**	Distribution Pipe	**Fail**	Dollar threshold	**48478**	KING: 22-YY-023 Dist Company Mains Leakage*	**2020**	$ 2,530,759									
Eastern	**Div_22 - Kingston**	Distribution Pipe	**Fail**	Dollar threshold	**100690**	King - Block Valve Assembly Maintenance (Various Locations))		$ 577,970									
Eastern	**Div_22 - Kingston**	Distribution Pipe	**Fail**	Dollar threshold	**100693**	King - King Street East Replacement (Prescott)	**2029**	$ 1,667,333									
Eastern	**Div_22 - Kingston**	Distribution Pipe	**Fail**	Dollar threshold	**100744**	King - Collins Bay NPS10 Shallow Pipe	**2023**	$ 1,284,159									
Eastern	**Div_22 - Kingston**	Distribution Pipe	**Fail**	Dollar threshold	**100746**	King - Property Line PLPRS Replacement (Various Locations)	**2025**	$ 190,930									
Eastern	**Div_22 - Kingston**	Distribution Pipe	**Fail**	Dollar threshold	**734706**	King: Thin Wall and Copper Pipe Replacement (Various Locations in Area)	**2032**	$ 583,717									

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Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
Eastern	**Div_22 - Kingston**	Distribution Pipe	**Fail**	Dollar threshold	**734740**	King: 520 Wallrich Ave. Service Block Valve Abandonment (Cornwall)	**2023**	$ 36,743									
Eastern	**Div_22 - Kingston**	Distribution Pipe	**Fail**	Dollar threshold	**734742**	King: Victoria Street Depth of Cover (Port Hope)	**2029**	$ 1,588,743									
Eastern	**Div_22 - Kingston**	Distribution Pipe	**Fail**	Dollar threshold	**734743**	King: Bath and Gardiners Valve Replacement (Kingston)	**2031**	$ 139,228									
Eastern	**Div_22 - Kingston**	Distribution Pipe	**Fail**	Dollar threshold	**734795**	King: HWY#2 Caravan Camp PRS Abandonment	**2023**	$ 43,594									
Eastern	**Div_22 - Kingston**	Distribution Pipe	**Fail**	Dollar threshold	**734921**	NPS 8 Augusta		$ 1,432,368									
Eastern	**Div_22 - Kingston**	Distribution Pipe	**Pass**		**30417**	Arthur St - Cornwall - Eastern - 1727	**2029**	$ 3,484,009	**General: Vintage Steel Replacement Program is a proactive replacement program to renew aging vintage steel pipe assets before reaching their end of life. Vintage steel mains have shown signs of declining health due to the cumulative effect 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 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.**	Planned							
Eastern	**Div_22 - Kingston**	Distribution Pipe	**Pass**		**30418**	Augustus St - Cornwall - Eastern - 1729	**2029**	$ 2,680,609	**Augustus St - Cornwall - Eastern - 1729Vintage steel exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (Vintage Steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization** **Comments: Remove York from 5th to 9th streets. Recently replaced - updated based on region's feedback (Augustus St - 1729) Road work on York in 2021 - removed York from project scope**	Planned							
Eastern	**Div_22 - Kingston**	Distribution Pipe	**Pass**		**30419**	Bridge St W-Napanee-1602	**2031**	$ 5,565,056	**Bridge St. W. - Napanee - 1602** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Complete	**Fail**	NPS 2, cannot downsize or retire					
Eastern	**Div_22 - Kingston**	Distribution Pipe	**Pass**		**30420**	Cedar Alley-Ganonoque-1455	**2032**	$ 3,399,815	**Cedar Alley - Ganonoque - 1455** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
Eastern	**Div_22 - Kingston**	Distribution Pipe	**Pass**		**30421**	Front St-Belleville-1592	**2030**	$ 5,630,449	**Front St. (moratorium until 2025) - Belleville - 1592** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: There has been road construction within last 3 years - project has been updated to reflect moratorium until 2025.**	Planned							
Eastern	**Div_22 - Kingston**	Distribution Pipe	**Pass**		**30423**	Garden Alley 2-Ganonoque-1494	**2028**	$ 3,968,189	**Garden Alley 2 - Ganonoque - 1494** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
Eastern	**Div_22 - Kingston**	Distribution Pipe	**Pass**		**30426**	Hickory St-Ganonoque-1454	**2031**	$ 2,673,449	**Hickory St - Gananoque - 1454** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: Elm and Hickory St. are deferred. Project is left as is and the moratorium should be complete once project is executed. Elm was within last five years; Victoria was repaved in the last seven years but has wide gravel shoulders; and Hickory St. was in the last ten years.**	Planned							
Eastern	**Div_22 - Kingston**	Distribution Pipe	**Pass**		**30428**	Main St - Ganonoque - Eastern - 1737	**2031**	$ 2,570,188	**Main St. - Gananoque - Eastern - 1737** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
Eastern	**Div_22 - Kingston**	Distribution Pipe	**Pass**		**30429**	Manse Alley-Ganonoque-1466	**2032**	$ 5,083,071	**Manse Alley - Ganonoque - 1466** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: Stone Street was done approximately 10 years ago.**	Complete	**Fail**	NPS 2, cannot downsize or retire					

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Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
Eastern	**Div_22 - Kingston**	Distribution Pipe	**Pass**		**30430**	Mcgill St-Trenton-1596	**2032**	$ 2,547,243	**McGill St. - Trenton - 1596** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: Dufferin St. was redone in last 10 years.**	Planned							
Eastern	**Div_22 - Kingston**	Distribution Pipe	**Pass**		**30432**	North Alley-Ganonoque-1468	**2032**	$ 2,476,197	**North Alley - Gananoque - 1468** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: Nothing within 10 years.**	Planned							
Eastern	**Div_22 - Kingston**	Distribution Pipe	**Pass**		**30436**	Victoria Ave-Ganonoque-1457	**2030**	$ 3,391,370	**Victoria Ave. - Gananoque - 1457** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
Eastern	**Div_22 - Kingston**	Distribution Pipe	**Pass**		**30470**	King St W - Eastern - 1799	**2027**	$ 2,079,659	**King St. W. - Eastern - 1799** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
Eastern	**Div_22 - Kingston**	Distribution Pipe	**Pass**		**48487**	KING: Anodes*	**2020**	$ 2,703,905	**General: The anodes program within the corrosion program includes the required expenditure to install anodes in order to reduce the amount of down plant within EGI's 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.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Eastern	**Div_22 - Kingston**	Distribution Stations	**Fail**	Dollar threshold	**49888**	KING: Ingredion Cardinal (18800003) Rebuild	**2024**	$ 865,092									
Eastern	**Div_22 - Kingston**	Distribution Stations	**Fail**	Dollar threshold	**100777**	KING - Under rated valve Trenton TBS 27601001	**2027**	$ 305,303									
Eastern	**Div_22 - Kingston**	Distribution Stations	**Fail**	Dollar threshold	**100835**	KING: Belleville Sidney St TBS (27801001) Valve Upgrades	**2026**	$ 319,290									
Eastern	**Div_22 - Kingston**	Distribution Stations	**Fail**	Dollar threshold	**100907**	King - corrosion Diamond Head Park PRS 27301037	**2023**	$ 87,187									
Eastern	**Div_22 - Kingston**	Distribution Stations	**Fail**	Dollar threshold	**101198**	KING: 22-22-704 College and Sidney DRS (27801009) Rebuild	**2024**	$ 1,325,309									
Eastern	**Div_22 - Kingston**	Distribution Stations	**Fail**	Dollar threshold	**503270**	Eastern PFM Compliance Program*		$ 359,005									
Eastern	**Div_22 - Kingston**	Distribution Stations	**Pass**		**101199**	KING - Cornwall East TBS rebuild	**2024**	$ 1,870,090	**Issue/Concern: With the decline in much of the area's industrial load (i.e., Domtar, Cortaulds, Celanese, and ICI Chemicals), it has been extremely difficult to balance the two stations since they tend to overtake each other. This has resulted in control issues with pressure regulation, measurement and odourization issues and concerns. A redesign is required to mitigate the concerns.**	Planned							
Eastern	**Div_22 - Kingston**	Growth	**Pass**		**30507**	SRP_LUG East_Kingston_28401002STN & Reinforcement_NPS12_1000m_1210kPa	**2024**	$ 6,217,387	**Station upgrades and relocation is required for additional capacity.**	Planned							
Eastern	**Div_22 - Kingston**	Growth	**Pass**		**30508**	SRP_LUG East_Barriefield_28403028STN_Rebuild	**2028**	$ 77,066	**Station upgrades are required for additional capacity.**	Planned							
Eastern	**Div_22 - Kingston**	Growth	**Pass**		**30509**	SRP_LUG East_Barriefield_28403029STN_Rebuild	**2023**	$ 186,830	**Higher maximum sustainable pressure is required.**	Planned							
Eastern	**Div_22 - Kingston**	Growth	**Pass**		**30510**	SRP_LUG East_Belleville_27802132STN_Rebuild	**2024**	$ 128,162	**Upgrades to existing station or a new station is needed for additional capacity.**	Planned							
Eastern	**Div_22 - Kingston**	Growth	**Pass**		**30512**	SRP_LUG East_Colborne_27401005STN_Rebuild	**2025**	$ 258,290	**Station upgrades are required for additional capacity.**	Planned							
Eastern	**Div_22 - Kingston**	Growth	**Pass**		**30513**	SRP_LUG East_Crysler_29401011STN_Rebuild	**2023**	$ 373,659	**Station upgrades are required for additional capacity.**	Planned							
Eastern	**Div_22 - Kingston**	Growth	**Pass**		**30514**	SRP_LUG East_Crysler_29401037STN_Rebuild	**2023**	$ 69,750	**Station upgrades are required for additional capacity.**	Planned							
Eastern	**Div_22 - Kingston**	Growth	**Pass**		**30515**	SRP_LUG East_Deseronto_28103002STN_Rebuild	**2023**	$ 186,830	**Station upgrades are required for additional capacity.**	Planned							
Eastern	**Div_22 - Kingston**	Growth	**Pass**		**30517**	SRP_LUG East_Grafton_27405001STN_Rebuild	**2027**	$ 346,936	**Station upgrades are required for additional capacity.**	Planned							
Eastern	**Div_22 - Kingston**	Growth	**Pass**		**30518**	SRP_LUG East_Picton_28103006STN_Rebuild	**2024**	$ 3,011,803	**Station upgrades are required for additional capacity.**	Planned							
Eastern	**Div_22 - Kingston**	Growth	**Pass**		**30519**	SRP_LUG East_Tweed_27805090STN_Rebuild	**2026**	$ 260,645	**Station upgrades are required for additional capacity.**	Planned							
Eastern	**Div_22 - Kingston**	Growth	**Pass**		**30520**	SRP_LUG East_Winchester_29301001STN_Rebuild	**2030**	$ 4,810,148	**Station upgrades are required for additional capacity.**	Planned							
Eastern	**Div_22 - Kingston**	Growth	**Pass**		**30521**	SRP_LUG East_Winchester_29301008STN_Rebuild	**2024**	$ 71,771	**Station upgrades are required for additional capacity.**	Planned							
Eastern	**Div_22 - Kingston**	Growth	**Pass**		**30522**	SRP_LUG East_Winchester_Main St_Reinforcement_NPS4_550m_1724kPa	**2028**	$ 619,279	**A 4-inch looping from outlet of Winchester TBS is required.**	Planned							
Eastern	**Div_22 - Kingston**	Growth	**Pass**		**48471**	KING: 22-21-001 Company Program - New Business - Scattered Mains - Contractor*	**2020**	$ 27,108,231	**Scattered Mains**	Planned							
Eastern	**Div_22 - Kingston**	Growth	**Pass**		**48497**	King - 22-20-709 McConnell Ave & Tollgate Rd PRS	**2024**	$ 352,445	**Issue/Concern/Opportunity: System Reinforcement is required; the existing Post Regulation Station (PRS) is undersized. Growth requires a rebuild but a relocate should be considered at the same time as this intersection will be getting widened soon. The existing station will eventually end up in a turning lane.** **Asset: not available** **Related Program: N/A**	Planned							
Eastern	**Div_22 - Kingston**	Growth	**Pass**		**100703**	SRP_LUG East_Kingston_Creekford Rd_Reinforcement_NPS8_6200m_6895kPa	**2024**	$ 28,702,886	**Issue/Concern/Opportunity: Kingston lateral replacement to be completed from Westbrook CMS to Woodbine TBS to account for forecast growth, and to address Class Location and depth of cover issues which exist on the current Kingston lateral.** **Assets: Kingston Lateral Replacement** **Related Program: N/A**	Planned							

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Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
Eastern	**Div_22 - Kingston**	Growth	**Pass**		**100778**	King - Chesterville, Crysler, Finch Reinforcement	**2023**	$ 311,383	**Issue/Concern/ Opportunity: The Chesterville, Finch and Crysler System is primarily fed from the Winchester TBS 29301001. The pipeline run is approx. 40KM and services residential houses and commercial scale farms that have installed or are currently looking to install crop dryers. This reinforcement is required to add additional capacity to the system and maintain healthy system pressures. This area has seen significant agricultural growth which has resulted in the system falling below minimum pressures. There have been a couple low pressure calls from the customers at the end of the system. Distribution Optimization Engineering have halted future main extensions and commercial attachments. If this reinforcement is not done, we would be unable to attach future customers. Asset: 40KM of NPS 4 Steel pipe Related programs: N/A**	Planned							
Eastern	**Div_22 - Kingston**	Growth	**Pass**		**102520**	King: 22-25-504 Tweed Reinforcement - McClellan and Pomeroy	**2025**	$ 284,119	**Issue/Concern/Opportunity: The southern end of the tweed system went below minimum pressure in 2020. Reinforcement is required to boost the pressures based on predicted growth as per Distribution Optimization Engineering. Assets : Connect 2-inch PE mains on McClellan ST and Pomeroy Ave. FID 517313684 ~150 m Related Program: N/A**	Planned							
Eastern	**Div_22 - Kingston**	Growth	**Pass**		**500423**	KING: Company Program - Customer Connections*		$ 68,257,533	**Kingston Customer Connections Program Items**	Planned							
Eastern	**Div_22 - Kingston**	Growth	**Pass**		**501482**	SRP_LUG East_Odessa_28405001STN_Rebuild	**2023**	$ 574,065	**Issue/Concern/Opportunity: Full rebuild is required as station becomes under capacity during fall peaking with the addition of new customer. The customer cannot come online unless station is rebuilt. Station is also aging and there are concerns regarding its integrity. Assets: Odessa TBS (28405001) Related Program: N/A**	Planned							
Eastern	**Div_22 - Kingston**	Growth	**Pass**		**734081**	King: 22-22-507 Second Street East - Tie NPS4 1210kPa Main Together	**2025**	$ 187,260	**Issue/Concern/Opportunity: SRPR Z13 2022_002 - Identified by Distribution Optimization Engineering (DOE) in June 2021. Two sections of NPS4 1,210 kPa main on Second Street at approximately #3306 are not tied together; both ends are capped off. A records research of Union and Centra Gas confirms that this section of main was broken in 1981 when linestoppers were installed and caps were welded on. Asset: Two sections of NPS4 1,210 kPa main on Second Street at approximately #330 Related Program: N/A**	Planned							
Eastern	**Div_22 - Kingston**	Growth	**Pass**		**734705**	King: Madoc Lateral MOP Upgrade (Belleville North)	**2030**	$ 2,354,399	**Issue/Concern/Opportunity: Complete a Maximum Operating Pressure (MOP) upgrade on the Madoc Lateral and mitigate service line clearance and Property Line Post Regulator Sets (PLPRS) issues. Assets: Madoc Lateral Related Program: N/A**	Planned							
Eastern	**Div_22 - Kingston**	Growth	**Pass**		**736264**	King: 22-25-508Brighton Reinforcement - Main Street	**2025**	$ 379,858	**Issue/Concern/Opportunity: Looping upgrades to account for connection of 291 Main St. and for future residential/commercial growth to the west. Asset: 300M NPS 4 Pipe Related Program: Additional reinforcements as part of 733975.**	Planned							
Eastern	**Div_22 - Kingston**	Utilization	**Pass**		**48483**	KING: Meter & Regulator Inst Repl-Company*	**2020**	$ 18,660,613	**Meter & Reg Install- Replacement**	Complete	**Fail**	See investment description, IRPAs not appliable					
GTA East	**30 - Richmond Hill**	Distribution Pipe	**Fail**	Dollar threshold	**4662**	Replacement Blanket - Area 30		$ 596,001									
GTA East	**30 - Richmond Hill**	Distribution Pipe	**Fail**	Dollar threshold	**30176**	Yonge St 2 - GTA East - Area 30 - 1707	**2028**	$ 1,618,990									
GTA East	**30 - Richmond Hill**	Distribution Pipe	**Fail**	Dollar threshold	**103419**	30: VSM - Major Mackenzie, Sussex To Newkirk, Replacement	**2023**	$ 1,541,431									
GTA East	**30 - Richmond Hill**	Distribution Pipe	**Pass**		**4668**	Anode Blanket - Area 30*	**2020**	$ 1,672,025	**General Description: The anodes program within the corrosion program includes the required expenditure to install anodes in order to reduce the amount of down plant within the EGI system. These installations and replacements are based on the Corrosion Operating Standard established to maintain the appropriate level of cathodic protection on steel pipeline assets.**	Complete	**Fail**	See investment description, IRPAs not appliable					
GTA East	**30 - Richmond Hill**	Distribution Pipe	**Pass**		**4764**	AMP Fitting Replacement - Area 30*	**2020**	$ 48,281,159	**AMP Fittings are a below grade transition fittings. The inserted portion of copper tubing can fail due to internal corrosion. In these cases leaks develop immediately downstream of the AMP Fitting.**	Complete	**Fail**	See investment description, IRPAs not appliable					
GTA East	**30 - Richmond Hill**	Distribution Pipe	**Pass**		**7666**	VSM - Major Mackenzie and Yonge	**2024**	$ 1,799,053	**Replacement of 287 m of NPS 6 steel main on Major Mackenzie from Newkirk Rd. to Cedar Ave. including the CN crossing.**	Planned							
GTA East	**30 - Richmond Hill**	Distribution Pipe	**Pass**		**13606**	Service Relay Blanket - Area 30*	**2020**	$ 19,997,215	**General: 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.**	Planned							
GTA East	**30 - Richmond Hill**	Distribution Pipe	**Pass**		**30162**	Ashlar Rd - GTA East - Area 30 - 1489	**2028**	$ 2,016,260	**Ashlar Rd. - GTA East - Area 30 - 1489 Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
GTA East	**30 - Richmond Hill**	Distribution Pipe	**Pass**		**30163**	Axminster Dr - GTA East - Area 30 - 1490	**2030**	$ 2,918,112	**Axminster Dr. - GTA East - Area 30 - 1490 Vintage steel pipes exhibit increased failures as they age, as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
GTA East	**30 - Richmond Hill**	Distribution Pipe	**Pass**		**30164**	Church St South_2 - GTA East - Area 30 - 1382	**2032**	$ 7,646,911	**Church St. South 2 - GTA East - Area 30 - 1382 Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							

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Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
GTA East	**30 - Richmond Hill**	Distribution Pipe	**Pass**		**30166**	Dunning Ave - GTA East - Area 30 - 1710	**2032**	$ 2,378,506	**Dunning Ave. - GTA East - Area 30 - 1710** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
GTA East	**30 - Richmond Hill**	Distribution Pipe	**Pass**		**30167**	Elgin Mills Rd E - GTA East - Area 30 - 1351	**2030**	$ 7,895,979	**Elgin Mills Rd. E. - GTA East - Area 30 - 1351** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
GTA East	**30 - Richmond Hill**	Distribution Pipe	**Pass**		**30168**	Paliser Cres S - GTA East - Area 30 - 1389	**2029**	$ 3,486,582	**Paliser Cres. S. - GTA East - Area 30 - 1389** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
GTA East	**30 - Richmond Hill**	Distribution Pipe	**Pass**		**30169**	Ruggles Ave - GTA East - Area 30 - 1706	**2027**	$ 3,071,774	**Ruggles Ave. - GTA East - Area 30 - 1706** **Vintage steel pipes exhibit increased failures as they age, as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: This was updated based on regional feedback (Ruggles Ave. - 1706).**	Complete	**Fail**	NPS 2, cannot downsize or retire					
GTA East	**30 - Richmond Hill**	Distribution Pipe	**Pass**		**30170**	Rupert Ave - GTA East - Area 30 - 1815	**2031**	$ 4,627,706	**Rupert Ave. - GTA East - Area 30 - 1815** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
GTA East	**30 - Richmond Hill**	Distribution Pipe	**Pass**		**30172**	Taylor Mills Dr S - GTA East - Area 30 - 1435	**2031**	$ 4,470,637	**Taylor Mills Dr. S. - GTA East - Area 30 - 1435** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
GTA East	**30 - Richmond Hill**	Distribution Pipe	**Pass**		**30173**	Tecumseth St - GTA East - Area 30 - 1362	**2032**	$ 4,945,270	**Tecumseth St. - GTA East - Area 30 - 1362** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
GTA East	**30 - Richmond Hill**	Distribution Pipe	**Pass**		**30174**	Wellington St - GTA East - Area 30 - 1417	**2031**	$ 4,327,256	**Wellington St. - GTA East - Area 30 - 1417** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
GTA East	**30 - Richmond Hill**	Distribution Pipe	**Pass**		**30175**	Yonge St - GTA East - Area 30 - 1358	**2029**	$ 4,149,594	**Yonge St. - GTA East - Area 30 - 1358** **Vintage steel exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
GTA East	**30 - Richmond Hill**	Distribution Pipe	**Pass**		**102421**	Relocation Program - Area 30*	**2020**	$ 18,602,801	**General: Projects in the relocation category are capital expenditures required to replace or relocate segments of pipeline in order to accommodate municipal infrastructure work. The cost sharing for this work is managed through the Franchise Agreements established with municipalities. A consultative approach is used between the municipality and EGI to avoid conflicts with municipal infrastructure early in the planning stage. If a conflict is unavoidable, pipeline assets are typically relocated or replaced.**	Planned							
GTA East	**30 - Richmond Hill**	Distribution Pipe	**Pass**		**103420**	30: VSM - Major Mackenzie, Cedar to Newkirk, Replacement	**2026**	$ 2,514,079	**Issue/Concern/Opportunity: Replace 40 m NPS 12 SC IP gas main, 645 m of NPS 6 SC IP gas main, 40 m of NPS 4 SC IP gas main, 100 m of NPS 2 SC IP, 40 m NPS 1.25 SC IP gas main, one district station (#8442841) and approximately 55 service relays.** **Justification: Richmond Hill Replacement Project** **Assets:** **Related Investments:**	Planned							
GTA East	**30 - Richmond Hill**	Distribution Stations	**Fail**	Dollar threshold	**18911**	COUNTY RD #55 HWY #9 DISTRICT (NEW TECUSETH)	**2023**	$ 144,018									
GTA East	**30 - Richmond Hill**	Distribution Stations	**Fail**	Dollar threshold	**23730**	LESLIE & STEELES DISTRICT	**2026**	$ 283,358									
GTA East	**30 - Richmond Hill**	Distribution Stations	**Fail**	Dollar threshold	**101056**	31428A - RAM FOREST & WESLEY CORNERS	**2023**	$ 305,493									
GTA East	**30 - Richmond Hill**	Distribution Stations	**Fail**	Dollar threshold	**101057**	32311A - WILLIAM & PRESTON LAKE DISTRICT	**2023**	$ 305,493									
GTA East	**30 - Richmond Hill**	Distribution Stations	**Fail**	Dollar threshold	**101058**	32717A - WESTON RD & KING RD DISTRICT	**2023**	$ 305,493									
GTA East	**30 - Richmond Hill**	Distribution Stations	**Fail**	Dollar threshold	**501533**	Beaverton District Station	**2025**	$ 129,173									
GTA East	**30 - Richmond Hill**	Distribution Stations	**Fail**	Dollar threshold	**733506**	Buttonville Interconnect	**2029**	$ 136,972									
GTA East	**30 - Richmond Hill**	Distribution Stations	**Fail**	Dollar threshold	**735169**	33534A STEELES & BAYVIEW DISTRICT	**2023**	$ 238,784									
GTA East	**30 - Richmond Hill**	Distribution Stations	**Fail**	Dollar threshold	**735170**	33171A - MAJOR MACKENZIE & VELLORE WOODS DISTRICT (VAUGHAN)	**2023**	$ 90,401									

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GTA East	**30 - Richmond Hill**	Distribution Stations	**Fail**	Dollar threshold	**735172**	30988A CONCESSION 2 & TWMARC DISTRICT	**2023**	$ 321,080									
GTA East	**30 - Richmond Hill**	Distribution Stations	**Fail**	Dollar threshold	**735173**	32564A - MILL ST & KING SIDEROAD DISTRICT	**2023**	$ 319,334									
GTA East	**30 - Richmond Hill**	Distribution Stations	**Fail**	Dollar threshold	**735300**	31335A GILBERT& YONGE DISTRIUCT (AURO	**2024**	$ 208,224									
GTA East	**30 - Richmond Hill**	Distribution Stations	**Fail**	Dollar threshold	**735301**	33300A ISLINGTON & HWY # 407 HP DIST	**2024**	$ 432,465									
GTA East	**30 - Richmond Hill**	Distribution Stations	**Fail**	Dollar threshold	**735302**	33525A Bathurst & Rutherford hp-ip	**2024**	$ 219,436									
GTA East	**30 - Richmond Hill**	Distribution Stations	**Fail**	Dollar threshold	**735303**	35053A Dufferin Langstaff (langstaff & 407)	**2024**	$ 221,038									
GTA East	**30 - Richmond Hill**	Distribution Stations	**Fail**	Dollar threshold	**735309**	50356A COUNTY RD #55 HWY #9 DISTRICT (NEW TECUSETH)	**2023**	$ 144,642									
GTA East	**30 - Richmond Hill**	Distribution Stations	**Pass**		**1011**	SCHOMBERG GATE	**2024**	$ 4,175,221	**Schomberg Gate Station is located on EGI-owned property of approximately 1,250 m2 fenced compound in the Township of King, Ontario, approximately 3 km from the town of Pottageville, within a rural/urban area, in close proximity to Kettleby. This station accepts natural gas from TC Energy and provides supply to two separate XHP networks, through components within the Measurement system, Pressure Control system, Heating system, Odourant system, and Telemetry system. This station supplies natural gas to approximately 23,501 customers in the King Region. The following issues have been identified at this station: Compliance: An engineering assessment of the site layout has identified a conflict with the location of the Telemetry or Boiler buildings with respect to the Electrical Safety Authority (ESA) Area Classification requirements which has identified that an ignition source is in close proximity to a potential leak source, as defined within the Electrical Codes and Standards. Measurement: The current system does not provide measurement of the individual outlet supplies. Visibility to each outlet supply provides greater redundancy to the existing measurement and improved response capabilities. Valve & Piping: The existing valves at this site have experienced issues in performance and operation of the valves. Maintenance has been performed to attempt to remediate the valves; however, the valves have deteriorated to the point where the reliability is no longer acceptable. Heating: The existing boilers at this site have experienced trouble call/failures over the recent years, including failures of the motors and pumps, burner lock-outs and exchanger failures. Due to recent and upcoming customer growth in the King area, the existing heating system will not be capable of supplying the heating requirements to meet the demand. Pressure Control: The Regulation system is undersized and not capable of supplying the demand required to meet the customer growth in the King area. The configuration of the existing regulators is double boot, posing an undesired higher risk and high associated ongoing maintenance costs. Telemetry & Electrical: The existing electrical system does not meet current EGI electrical installation standards. This poses a potential electrical hazard and faulty wiring may result in lost communications.**	Planned							
GTA East	**30 - Richmond Hill**	Distribution Stations	**Pass**		**1013**	MARKHAM GATE	**2027**	$ 6,498,238	**Markham Gate Station Pipe, Valves & Others: Updated Mechanical Piping is required for this station. The existing valves at this site have experienced issues in performance and operation of the valves. Maintenance has been performed to attempt to remediate the valves, however, the valves have deteriorated to the point where the reliability is no longer acceptable Heating System: Updated heating is required at this station. New Heat Exchanger is required including the associated piping for the glycol inlet and outlet to heating element. New boiler building will be procured as the existing building is within the ESA classification. Pressure Control: Not Required Odorant System: New Odorant system is required. This would include a new Odorant building including tank (Assume 500G – Enbridge standard). New Odorant cabinet including 2 new pumps and associated tubing from the tank equipment to cabinet. New sight glass for injection point is required. New odorant building to be outfitting with new electrical distribution and internal/external lighting. Galvanized building stairs to be accounted for. Telemetry/Electrical: New Control Wave Micro unit required and associated connections. Account for 1 new pressure transmitter and 1 new temperature transmitter. The telemetry and electrical systems do not meet current EGI standards, do not contain backup power supply in the event of power loss, and are approaching end of useful life. The existing RTU is obsolete and is required to be upgraded to current standards along with new communications equipment in order to eliminate cyber security threats. New Telemetry building will be required to be installed in new compliance location. Measurement: No information provided. Building: New Odorant Building required (See Odorant Scope for details). Additionally, new boiler building will need to be procured. An engineering assessment of the site layout has identified a conflict with the location of the telemetry or boiler Buildings with respect to the ESA Area Classification**	Planned							
GTA East	**30 - Richmond Hill**	Distribution Stations	**Pass**		**1148**	BATHURST GATE	**2025**	$ 4,125,265	**The regulators are heavy and maintenance is difficult in the current arrangement, a lifting device is needed for ergonomic reasons. The current heating system consists of condensing boilers that have condensate which will reguire mitigation. A conversion to noncondensing boilers is required and during the conversion three-way valves and associated piping (6,000 by Stations Ops) will be added. The front gate experiences flooding and teh grade by the gate needs to be raised because water pools at the main gate.**	Planned							
GTA East	**30 - Richmond Hill**	Distribution Stations	**Pass**		**3614**	BOND HEAD GATE	**2026**	$ 6,906,783	**Bond Head Gate Station is located on EGI-owned property of approximately 1,900 m2 fenced compound in the village of Bond Head, Ontario, approximately 8.5 km west of Bradford Ontario, within a rural area, in close proximity to several homes. This station accepts natural gas from TC Energy and provides supply to two separate XHP networks and one IP network, through components within the measurement system, pressure control system, heating system, odourant system, and telemetry system. This station supplies natural gas to approximately 60,000 customers in the Alliston, Orangeville, Bradford, and northern York Region. The following issues have been identified at this station: Compliance: An engineering assessment of the site layout has identified a conflict with the location of the Telemetry or Boiler buildings with respect to the Electrical Safety Authority (ESA) Area Classification requirements which has identified that an ignition source is in close proximity to a potential leak source, as defined within the Electrical Codes and Standards. Valves & Piping: The existing valves at this site have experienced issues in performance and operation of the valves. Maintenance has been performed to attempt to remediate the valves; however, the valves have deteriorated to the point where the reliability is no longer acceptable. Measurement: The current Turbine meter does not provide measurement of the individual outlet supplies. Visibility to each outlet supply provides greater redundancy to the existing measurement and improved response capabilities. As well, failures have been experienced over the past year including complete meter failure and jamming. Station has a backup orifice plate meter, which has experienced several alarms. Heating: The existing boilers at this site are approaching 20 years old, they have had 10 trouble call/failures over the recent years, including failures of the motors and pumps, burner lock-outs and exchanger failures. Due to recent and upcoming customer growth in the Bradford/York Region area, the existing heating system will not be capable of supplying the heating requirements to meet the demand. Pressure Control: The regulation system is undersized and not capable of supplying the demand required to meet the customer growth in the Bradford/York Region area. The configuration of the existing regulators are double boot, posing an undesired higher**	Planned							

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GTA East	**30 - Richmond Hill**	Distribution Stations	**Pass**		**3624**	VICTORIA SQUARE GATE	**2024**	$ 1,737,072	**Pipe, Valves and Others: Current actuators on the inlet, outlet and heat exchanger valves need to be commissioned and programmed for remote control by Gas Control in the Remoter Terminal Unit (RTU). The RTU will have to be upgraded to accommodate the additional input/output (I/O) as its current capacity is full. NPS 8 Becker control valve was replaced in 2016. Fuel gas supply and meter set will be required to replace outdated station.** **Measurement: The existing Measurement system is scheduled for upgrade in 2019 and it is expected that this work will be sufficient for operation in 2024. No upgrade to the Measurement system is included in this business case.** **Heating System: Existing Heating system is not in compliance with the Area Classification and will require boiler building relocation. The boilers have recently been replaced and should continue to operate. The boiler building is location in a classified area and will have to be moved and/or remediated. Exhaust fans may resolve the issue but this will be determined in detailed engineering. Heat exchangers were recently inspected (2015/2016) and will not require replacement.** **Pressure Control: Low flow regulator run was added in 2017. No additional work is required on the regulation runs.** **Odourant: Install a new Odourant building as the current metallic odourant building is without adequate containment. This building rusts, leaks in rain and spill response is hampered due to difficulty wrapping the building. The tank has bottom connections to feed the injection pumps. Odourant pumps are also in a different building and will be located appropriately in the same building as the 3,500 gallon odourant tank. This tank will have to be upsized.** **Telemetry/Electrical: RTU replacement is required from an old Bristol 3330 to a new control wave RTU. RTU upgrade is required as the current design has no available expansion capacity to accommodate new actuator, measurement inputs, additional methane and CO sensing. This will require a new RTU building. Electrical Safety Authority (ESA) compliance Issues will be resolved by relocating electrical equipment. Upgrades to station wiring will be required to allow for new instrumentation. The electrical service will be upgraded to accommodate the new station loads. A new station grounding network, updated anti-climb tower, and updated instrumentation will be installed to meet current standards. A generator (installed 1999) and UPS system will be installed for backup power requirements in the event of a power outage. A new modem and firewall, improved station lighting, odourant tank**	Planned							
GTA East	**30 - Richmond Hill**	Distribution Stations	**Pass**		**7753**	NOBLETON GATE	**2026**	$ 4,302,068	**Issue/Concern: Nobleton Gate Station is located on a fenced, EGI-owned property of approximately 1,000 m2 in the City of Vaughan, Ontario, approximately 3 km from the Town of Nobleton, within a rural area. This station accepts natural gas from TC Energy and provides supply to an XHP network, with a Measurement system, Pressure Control system, Heating system, Odourant system, and a Telemetry and Controls system. This station supplies natural gas to approximately 1,800 customers in the Bolton and King City areas. The following issues have been identified at this station:** **Compliance: An engineering assessment of the site layout has identified a conflict with the location of the Telemetry and Boiler buildings with respect to the Electrical Safety Authority (ESA) area classification requirements, which have identified that an ignition source is in close proximity to a potential leak source, as defined within the Electrical Codes and Standards. Additional property will be required to remediate the area classification issue.** **Measurement: Gas measurement is completed using a turbine meter installed in 2004. This meter type has experienced failures causing potential downstream impacts and loss of service to customers. This meter has experienced six failures in the past two years, due to leaks and faulty measurement. A new mass flow meter will be installed to replace the turbine meter and a backup outlet Annubar meter will also be installed.** **Heating: The existing boilers at this site are 14 years old. They have had three trouble call/failures over the past year including failures of the motors and pumps, burner lock-outs and exchanger failures. The boilers, building, and glycol piping require replacement as they will be 20 years old by the target rebuild date. The heat exchanger is not expected to be replaced but inspection is to be included.** **Pressure Control: The regulators are the original regulators installed when the station was first commissioned. In 2001, a building was installed over them to improve maintenance and operation. The regulators have experienced 29 trouble calls/failures in the time period including leaks, boot failures, and pilot failures. Both monitor and operator runs are boot-style regulators, which poses an undesired higher risk and high associated ongoing maintenance costs.** **Odourization: The odourant system was installed in 2004 with the injection system installed in 2009. The current configuration of**	Planned							
GTA East	**30 - Richmond Hill**	Distribution Stations	**Pass**		**7769**	KEELE AND STEELES/CNR FEEDER	**2025**	$ 2,321,253	**Keele and Steeles/CNR Feeder Station is located on 3,000 m2 compound in the city of Vaughan, Ontario, approximately 1.5 km from York University, within an urban area in close proximity to CNR Railway Corridor. This station accepts natural gas from EGI XHP pipeline and provides supply to three separate XHP networks and an HP network, through components within the Pressure Control system, Heating system, Odourant system, and Telemetry system. This station supplies natural gas to approximately 20,000 customers in Vaughan and Toronto area. The following issues have been identified at this station:** **Valve & Piping: the existing valves at this site have experienced 10 failures and leak issues in performance and operation of the valves. Maintenance has been performed to attempt to remediate the valves; however, the valves have deteriorated to the point where the reliability is no longer acceptable.** **Pressure Control: The configuration of the existing regulators was installed in 1990 and is double boot, posing an undesired higher risk and high associated ongoing maintenance costs. The existing regulators have reached end of life.** **Telemetry & Electrical: The Telemetry and Electrical systems do not meet current EGI standards, do not contain backup power supply in the event of power loss, and are approaching end of useful life. The existing Remote Terminal Unit (RTU) is obsolete and is required to be upgraded to current standards along with new communications equipment in order to eliminate cybersecurity threats.**	Planned							
GTA East	**30 - Richmond Hill**	Distribution Stations	**Pass**		**7778**	WOODBINE & CNR FEEDER	**2024**	$ 2,134,241	**Pipe, Valves & Others: Not required.** **Heating System: Not required.** **Pressure Control: Not required.** **Odourant System: A new Odourant system is required. This would include a new Odourant building including tank (assume 500 G – EGI standard). A new Odourant cabinet including two new pumps and associated tubing from the tank equipment to cabinet is required. A new sight glass for injection point is required. New Odourant building is to be outfitted with new electrical distribution and internal/external lighting. Galvanized building stairs are to be accounted for.** **Telemetry/Electrical: New Control Wave Micro unit and associated connections are required. One new pressure transmitter and one new temperature transmitter are to be accounted for. The Telemetry and Electrical systems do not meet current EGI standards, do not contain backup power supply in the event of power loss, and are approaching end of useful life. The existing Remote Terminal Unit (RTU) is obsolete and is required to be upgraded to current standards along with new communications equipment in order to eliminate cybersecurity threats.** **Measurement: Not required.** **Building: New Odourant building is required** **Compliance/Civil: Minor site grading, new crash bar access and two sides of site will be required.**	Planned							

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GTA East	**30 - Richmond Hill**	Distribution Stations	**Pass**		**8567**	St John Sideroad Feeder Station	**2023**	$ 7,020,635	**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 Remote Terminal Unit (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: Not applicable.**	Planned							
GTA East	**30 - Richmond Hill**	Growth	**Pass**	(blank)	**3736**	Area 30 - Industrial - New Construction*		$ 694,952	**Industrial New Construction- A customer intending to run an industrial manufacturing business in a newly-built facility and intending to use natural gas. Issue/Concern: EGI is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGI will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGD develops a customer additions forecast using a number of information sources: - Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities - Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates - Projections developed by external consultants specializing in population growth forecasting - Municipal long term plans EGI extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report. Enbridge reviews the following when determining feasibility: - The number of potential new customers - The consumption of natural gas by new customers; and, - The cost of extending the gas main The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGI determines the CIAC amount and communicate with the applicant(s) in writing Assets: Generally, there are three components of capital investments needed to support customer addition requirements: - Installation costs related to mains, services, and meters - Material costs related to mains, services and meters - Costs related to measurement and regulation equipment required to support customer growth**	Planned							
GTA East	**30 - Richmond Hill**	Growth	**Pass**		**2522**	Rodinea Road	**2023**	$ 589,364	**Issue/Concern/Opportunity: The HP network system needs reinforcement through this proposed piping connection. This project is to address system capacity loss due to a previous transit-related main abandonment in Area 10.** **Assets: install 223m of 8" steel HP gas main to connect mains at the east and the west side. HDD under the railroad.** **Related Program: N/A**	Planned							
GTA East	**30 - Richmond Hill**	Growth	**Pass**		**3731**	Area 30 - Apartment Ensuite - New Construction*		$ 4,136,135	**Issue/Concern: Vertical Subdivision refers to a multiple unit residential building where each suite is individually metered. Issue/Concern: EGI is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGI will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGI develops a customer additions forecast using a number of information sources: - Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities - Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates - Projections developed by external consultants specializing in population growth forecasting - Municipal long-term plans: EGI extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report. EGI reviews the following when determining feasibility: - The number of potential new customers - The consumption of natural gas by new customers - The cost of extending the gas main The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGI determines the CIAC amount and communicate with the applicant(s) in writing. Generally, there are three components of capital investments needed to support customer addition requirements: - Installation costs related to mains, services, and meters - Material costs related to mains, services and meters - Costs related to measurement and regulation equipment required to support customer growth.** **Assets: All applicable assets.** **Related Program: N/A**	Planned							
GTA East	**30 - Richmond Hill**	Growth	**Pass**		**3735**	Area 30 - Commercial - New Construction*		$ 46,840,812	**Issue/Concern: Commercial New Construction refers to a customer intending to run a commercial business in a newly-constructed building and intending to using natural gas to meet energy needs.** **Issue/Concern: EGI is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGI will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGI develops a customer additions forecast using a number of information sources: - Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities - Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates - Projections developed by external consultants specializing in population growth forecasting - Municipal long-term plans: EGI extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report. EGI reviews the following when determining feasibility: - The number of potential new customers - The consumption of natural gas by new customers - The cost of extending the gas main The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGI determines the CIAC amount and communicate with the applicant(s) in writing. Generally, there are three components of capital investments needed to support customer addition requirements: - Installation costs related to mains, services, and meters - Material costs related to mains, services and meters - Costs related to measurement and regulation equipment required to support customer growth.** **Assets: All applicable assets.** **Related Program: N/A**	Planned							

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Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
GTA East	30 - Richmond Hill	Growth	Pass		3738	Area 30 - Residential - New Construction*		$ 77,074,340	Issue/Concern: Residential New Construction refers to a new residential construction development of detached single homes constructed by the builder for domestic purposes. Issue/Concern: EGI is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGI will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGI develops a customer additions forecast using a number of information sources: - Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities - Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates - Projections developed by external consultants specializing in population growth forecasting - Municipal long-term plans: EGI extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report. EGI reviews the following when determining feasibility: - The number of potential new customers - The consumption of natural gas by new customers - The cost of extending the gas main The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGI determines the CIAC amount and communicate with the applicant(s) in writing. Generally, there are three components of capital investments needed to support customer addition requirements: - Installation costs related to mains, services, and meters - Material costs related to mains, services and meters - Costs related to measurement and regulation equipment required to support customer growth. Assets: All applicable assets. Related Program: N/A	Planned							
GTA East	30 - Richmond Hill	Growth	Pass		3739	Area 30 - Residential - Replacement*		$ 42,584,538	Issue/Concern: Residential Replacement refers to a residential replacement customer using a fuel other than natural gas for domestic purposes and is converting to natural gas. Issue/Concern: EGI is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGI will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGI develops a customer additions forecast using a number of information sources: - Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities - Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates - Projections developed by external consultants specializing in population growth forecasting - Municipal long-term plans: EGI extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report. EGI reviews the following when determining feasibility: - The number of potential new customers - The consumption of natural gas by new customers - The cost of extending the gas main The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGI determines the CIAC amount and communicate with the applicant(s) in writing. Generally, there are three components of capital investments needed to support customer addition requirements: - Installation costs related to mains, services, and meters - Material costs related to mains, services and meters - Costs related to measurement and regulation equipment required to support customer growth. Assets: All applicable assets. Related Program: N/A	Planned							
GTA East	30 - Richmond Hill	Growth	Pass		736389	A30: Interchange Way Reinf	2023	$ 640,984	Issue/Concern/Opportunity: There is future growth in the area from addition of condo towers and some commercial work. Justification: Existing NPS 4 Steel (ST) High Pressure (HP) gas main will need to be upsized to NPS 12 ST HP to support future load on system. Assets: N/A Related Investments: N/A	Planned							
GTA East	30 - Richmond Hill	Growth	Pass		736532	NW 3723 Jane St. Reinforcement SRP	2024	$ 993,023	Issue/Concern/Opportunity: Install 1,280 m of NPS 4 PE Intermediate Pressure (IP) along Jane St. from King Rd., tying into NPS 2 main at Westgate Blvd. System pressures were projected to fall below minimum system pressures in 2022. Station 3577117 will need to be upsized due to station drooping and reaching capacity. Assets: Pipe and district station Related Program: Not applicable	Planned							
GTA East	30 - Richmond Hill	Utilization	Pass		13545	MXGI Area 30*	2019	$ 51,771,809	Meters: Meters are used to determine the gas consumption input of customer billing. The replacement program for meters is mandated by Measurement Canada. The program includes: testing, repair, and replacement requirements of meters and instruments. All verified meters are approved by Measurement Canada with an issuance of a certificate which identifies that the meter complies with Electricity and Gas Specification S-EG-02. The Company must ensure all measurement devices remain in compliance for annual audits by Measurement Canada. Measurement Canada specifies tolerances under which the meter must operate in the field. The Company must demonstrate that all aspects of its meter sampling, maintenance, and replacement comply with these criteria in order to be accredited by Measurement Canada to be an "Authorized Service Provider" and adhere to Measurement Canada's accreditation standard S-A-01. Meters may also require exchange for issues such as: damages, leaks, customer billing issues. Regulation: Regulators are the last line of defense for over-pressure to the customer. The condition of regulation systems is determined by regulator performance, corrosion of piping and regulators, and adherence to installation specifications. Failure of the regulation system can cause pressured gas to enter the premise, resulting in failure of gas equipment, loss of containment, and potentially fire or explosion.	Complete	Fail	See investment description, IRPAs not appliable					
GTA East	30 - Richmond Hill	Utilization	Pass		503324	LEG: AMI Pilot Project	2023	$ 1,870,367	AMI Pilot Project Purpose & Need The AMI initiative is a key piece required to successfully test AMI & AMR functionality The AMI pilot is a proof of concept that will ensure when a large scale program is launched the greatest benefits will be gained. The Markham piece of the pilot will include approximately 3500 customers, each customer will have a new ultrasonic meter installed The new meters increase efficiency, reduce costs, provide extra safety features, and give real time consumption data to help model the distribution network, provide DSM opportunities, and assist with maintenance scheduling Some of the benefits of the new advanced system: Two way communication , Real time consumption, Increased meter data – example: pressure sensors, methane detectors, and shut off capabilities Key components required for a successful pilot: Communications / Accuracy / Functionality / Reporting / Reliability / Safety / Cyber Security Timing The pilot project will be rolled out in 2022 The pilot project will operate in 2022 and 2023 Any barriers/issues will be solved during the operational period	Complete	Fail	See investment description, IRPAs not appliable					
GTA East	40 - Whitby	Distribution Pipe	Fail	Dollar threshold	4663	Replacement Blanket - Area 40		$ 485,846									
GTA East	40 - Whitby	Distribution Pipe	Fail	Dollar threshold	13607	Service Relay Blanket - Area 40*	2020	$ 15,804,346									

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GTA East	**40 - Whitby**	Distribution Pipe	**Fail**	Dollar threshold	**14147**	Copper Service Replacement - Area 40*	**2020**	$ 846,997									
GTA East	**40 - Whitby**	Distribution Pipe	**Fail**	Dollar threshold	**30183**	Howard Ave 1 - Kawartha Lakes - Area 40 - 1692	**2027**	$ 925,866									
GTA East	**40 - Whitby**	Distribution Pipe	**Fail**	Dollar threshold	**30184**	Howard Ave 2 - Kawartha Lakes - Area 40 - 1694	**2031**	$ 1,740,886									
GTA East	**40 - Whitby**	Distribution Pipe	**Fail**	Dollar threshold	**30189**	Prospect St-Bowmanville-1086	**2030**	$ 1,371,368									
GTA East	**40 - Whitby**	Distribution Pipe	**Fail**	Dollar threshold	**30190**	Regent St - Kawartha Lakes - Area 40 - 1697	**2028**	$ 817,509									
GTA East	**40 - Whitby**	Distribution Pipe	**Fail**	Dollar threshold	**100470**	Bannerman Crt. and Nordic Crt, Whitby	**2023**	$ 910,371									
GTA East	**40 - Whitby**	Distribution Pipe	**Fail**	Dollar threshold	**102671**	Campbellford Replacement Phase 3 Front St	**2029**	$ 851,261									
GTA East	**40 - Whitby**	Distribution Pipe	**Fail**	Dollar threshold	**102672**	Campbellford Replacement Phase 4 Kent St	**2023**	$ 1,446,589									
GTA East	**40 - Whitby**	Distribution Pipe	**Fail**	Dollar threshold	**102673**	Campbellford Replacement Phase 5 Pellissier St & Bridge St	**2028**	$ 1,050,158									
GTA East	**40 - Whitby**	Distribution Pipe	**Pass**		**4669**	Anode Blanket - Area 40*	**2020**	$ 1,535,938	**General Description: The anodes program within the corrosion program includes the required expenditure to install anodes in order to reduce the amount of down plant within the EGI system. These installations and replacements are based on the Corrosion Operating Standard established to maintain the appropriate level of cathodic protection on steel pipeline assets.**	Complete	**Fail**	See investment description, IRPAs not appliable					
GTA East	**40 - Whitby**	Distribution Pipe	**Pass**		**4766**	AMP Fitting Replacement - Area 40*	**2020**	$ 28,398,914	**AMP Fittings are a below grade transition fittings. The inserted portion of copper tubing can fail due to internal corrosion. In these cases leaks develop immediately downstream of the AMP Fitting.**	Complete	**Fail**	See investment description, IRPAs not appliable					
GTA East	**40 - Whitby**	Distribution Pipe	**Pass**		**30178**	Caddy St-Peterborough-1179	**2032**	$ 3,960,180	**Caddy St. - Peterborough - 1179** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
GTA East	**40 - Whitby**	Distribution Pipe	**Pass**		**30179**	Christena Cres 1 - Ajax - Area 40 - 1702	**2030**	$ 3,285,942	**Christena Cres. 1 - Ajax - Area 40 - 1702** **Vintage steel pipes exhibit increased failures as they age, as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: Scope is to be broken up into two investments given the large scope and potential conservation concerns and close proximity to MTO right-of-way (ROW). Project will be adjusted based on regional comments (Christena Cres. 1 - 1702 and Christena Cres. 2 - 1704).**	Planned							
GTA East	**40 - Whitby**	Distribution Pipe	**Pass**		**30181**	Durham St W - Kawartha Lakes - Area 40 - 1687	**2031**	$ 5,109,709	**Durham St. W. - Kawartha Lakes - Area 40 - 1687** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
GTA East	**40 - Whitby**	Distribution Pipe	**Pass**		**30182**	Euclid Ave-Peterborough-1106	**2030**	$ 4,142,300	**Euclid Ave. - Peterborough - 1106** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
GTA East	**40 - Whitby**	Distribution Pipe	**Pass**		**30186**	Poplar Ave 1 - Ajax - Area 40 - 1680	**2032**	$ 4,731,770	**Poplar Ave. 1 - Ajax - Area 40 – 1680** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: This scope could be broken up into two projects given the conservation authority impacts - project adjusted based on region's comments (Poplar Ave 1 - 1680 and Poplar Ave 2 - 1681).**	Planned							
GTA East	**40 - Whitby**	Distribution Pipe	**Pass**		**30187**	Poplar Ave 2 - Ajax - Area 40 - 1681	**2029**	$ 2,371,613	**Poplar Ave. 2 - Ajax - Area 40 - 1681** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: This scope could be broken up into two projects given the conservation authority impacts; project was adjusted based on region's comments (Poplar Ave. 1 - 1680 and Poplar Ave. 2 - 1681)**	Complete	**Fail**	NPS 2, cannot downsize or retire					
GTA East	**40 - Whitby**	Distribution Pipe	**Pass**		**30188**	Prince St-Bowmanville-1450	**2029**	$ 2,275,535	**Prince St. - Bowmanville - 1450** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
GTA East	**40 - Whitby**	Distribution Pipe	**Pass**		**30192**	Simcoe Street-40-Kawartha Lakes-1060	**2028**	$ 3,081,605	**Simcoe Street - 40 - Kawartha Lakes - 1060** **Vintage steel pipes exhibit increased failures as they age, as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Complete	**Fail**	NPS 2, cannot downsize or retire					

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GTA East	40 - Whitby	Distribution Pipe	Pass		30193	Tulloch Dr-Ajax-1594	2031	$ 4,233,089	Tulloch Dr. - Ajax - 1594 Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.	Planned							
GTA East	40 - Whitby	Distribution Pipe	Pass		30194	Wellington St - Kawartha Lakes - Area 40 - 1678	2032	$ 4,398,636	Wellington St. - Kawartha Lakes - Area 40 - 1678 Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.	Planned							
GTA East	40 - Whitby	Distribution Pipe	Pass		30196	Windsor Dr-Ajax-1193	2027	$ 2,191,889	Windsor Dr. - Ajax - 1193 Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.	Planned							
GTA East	40 - Whitby	Distribution Pipe	Pass		100517	Oshawa LP Replacement Phase 1 Olive Ave	2024	$ 4,209,858	Issue/Concern/Opportunity: Overall goal is to eventually replace the Oshawa Low Pressure network, reducing the risk of an overpressure on a system with no additional overpressure protection downstream of the district stations. Justification: This phase will follow Phase 1a (Olive Ave. replacement in 2020), and will allow for the abandonment of one of the low-pressure district stations with external sense lines. Assets: Replace approximately 3,000 m of PE and steel low-pressure main, and relay or reconnect approximately 400 services, including installation of regulators at the meter sets. Related Investments: Not applicable.	Planned							
GTA East	40 - Whitby	Distribution Pipe	Pass		101277	Replacement - Vintage PE Lined Mains - Peterborough	2023	$ 2,723,457	Issue/Concern/Opportunity: This is a planned replacement of approximately 320 m of vintage PE pipe (1974) lined in old cast iron mains, installed in back laneways on Elias Ave., Maitland Ave., Pearl Ave., and Boswell Ave. in Peterborough. Justification: Vintage PE mains are reaching their life expectancy. Mains are cased in cast iron, making leaks difficult to pinpoint. Assets: There are 1974 NPS 1 1/4 PE mains (approximately 320 m) to be replaced with new NPS 2 PE mains (approximately 960 m if dual main) and there are approximately 60 service relays. Related Investments: Not applicable.	Planned							
GTA East	40 - Whitby	Distribution Pipe	Pass		102422	Relocation Program - Area 40*	2020	$ 42,520,689	General: Projects in the relocation category are capital expenditures required to replace or relocate segments of pipeline in order to accommodate municipal infrastructure work. The cost sharing for this work is managed through the Franchise Agreements established with municipalities. A consultative approach is used between the municipality and EGI to avoid conflicts with municipal infrastructure early in the planning stage. If a conflict is unavoidable, pipeline assets are typically relocated or replaced.	Planned							
GTA East	40 - Whitby	Distribution Pipe	Pass		103427	Oshawa LP Replacement Phase 2 King St	2026	$ 5,166,299	Issue/Concern/Opportunity: Overall goal is to eventually replace the Oshawa Low Pressure network, reducing the risk of an overpressure on a system with no additional overpressure protection downstream of the district stations. It consists of Vintage steel main. Justification: This phase will follow Phase 1 - Olive Ave. Replacement in 2021 is timed with municipal work; it will allow for the abandonment of one of the low-pressure district stations with external sense lines. Assets: Replace approximately 7,600 m of PE and ST low-pressure main. Relay or reconnect approximately 300 services, including installation of regulators at the meter sets. Related Investments: Not applicable.	Planned							
GTA East	40 - Whitby	Distribution Pipe	Pass		103429	Oshawa LP Replacement Phase 3 Masson St	2026	$ 8,767,138	Issue/Concern/Opportunity: Overall goal is to eventually replace the Oshawa Low Pressure network, reducing the risk of an overpressure on a system with no additional overpressure protection downstream of the district stations. Justification: This phase will follow Phase 2 King St. Replacement in 2024 and will allow for the abandonment of one of the low-pressure district stations with external sense lines. Assets: Replace approximately 8,064 m of PE and steel low-pressure main. Relay or reconnect approximately 748 services, including installation of regulators at the meter sets. Related Investments: Not applicable.	Planned							
GTA East	40 - Whitby	Distribution Pipe	Pass		735948	AR40: VSM Replacement - Wilson Rd S Oshawa Ph 1 Bloor to Olive	2026	$ 5,731,466	Issue/Concern/Opportunity: There is vintage 12-inch steel high-pressure (HP) main with several potential maintenance risks. Justification: Main was ranked as HI 5 in recent Asset Health Review (AHR). It was installed in 1957, has multiple service connections with corrosion risk and possible unknown compression couplings. Assets: There is 950 m 12-inch ST HP main and approximately 30 services in Phase 1 Bloor St. to Olive Ave. Related Investments: Not applicable.	Planned							
GTA East	40 - Whitby	Distribution Pipe	Pass		735949	AR40: VSM Replacement - Wilson Rd S Oshawa Ph 2 Olive to King	2026	$ 5,846,848	Issue/Concern/Opportunity: There is vintage 12-inch steel high-pressure (HP) main with several potential maintenance risks. Justification: Main was ranked as HI 5 in recent Asset Health Review (AHR). It was installed in 1957, has multiple service connections with corrosion risk and possible unknown compression couplings. Assets: 1,247m 12-inch ST HP main and approximately 30 services in Phase 2 Olive Ave. to Bloor St. Related Investments: Not applicable.	Planned							
GTA East	40 - Whitby	Distribution Stations	Fail	Dollar threshold	7763	CATHCART & STEWART DISTRICT	2025	$ 1,451,991									
GTA East	40 - Whitby	Distribution Stations	Fail	Dollar threshold	501531	GM South Station	2023	$ 124,691									
GTA East	40 - Whitby	Distribution Stations	Fail	Dollar threshold	501532	Peterborough District Station	2023	$ 124,691									

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Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
GTA East	40 - Whitby	Distribution Stations	Fail	Dollar threshold	735168	44512A YANKEE LINE & RUSSELL DISTRICT	2023	$ 277,438									
GTA East	40 - Whitby	Distribution Stations	Fail	Dollar threshold	735304	2885749 Taunton and Gillett	2024	$ 384,413									
GTA East	40 - Whitby	Distribution Stations	Pass		7749	BOWMANVILLE GATE	2025	$ 4,964,375	Issue/Concern: Bowmanville Gate Station is located on fenced EGI-owned property of approximately 700 m2 in Clarington, Ontario. It is approximately 5 km north of Newcastle Ontario, within a rural area. This station accepts natural gas from TC Energy and provides supply to two separate XHP networks, through a measurement system, pressure control system, gas pre-heat system, odourant injection system, and telemetry and controls system. This station supplies natural gas to approximately 61,000 customers in an area that spans from Bowmanville to Lindsay. The following issues have been identified at this station: Valves and Piping: The existing valves at this site have experienced issues in performance and operation of the valves. Maintenance has been performed to attempt to remediate the valves; however, the valves have deteriorated to the point where the reliability is no longer acceptable. The inlet piping to the heat exchanger shows signs of deterioration and should be replaced. The station is located close to Hwy 35/115 and its proximity to traffic puts it at a higher risk. The piping is to be relocated away from the road, as far as practical. Measurement: The current system does not provide measurement of the individual outlet supplies. Visibility to each outlet supply provides redundancy to the existing measurement, odourant injection reliability, and improved response capabilities. The turbine meter is to be replaced with a Coriolis meter. Heating: The existing boilers at this site are 18 years old, they have had 42 trouble call/failures over the life of the heating system, including failures of the motors and pumps, burner lock-outs and exchanger failures. The system, including buildings, will require replacement as it approaches end of life. Odourization: The odourant system was installed in 1999. The current configuration of the odourant system does not ensure adequate containment of the odourant product in the event of a leak and does not meet the current engineering standards and approvals. The building is an old-style, rusted metallic odourant building without adequate containment and a new building, tank, and Odourant Injection system will be required. Telemetry and Electrical: The existing Electrical system does not meet current EGI electrical installation standards. This poses a potential electrical hazard and faulty wiring may result in lost communications.	Planned							
GTA East	40 - Whitby	Distribution Stations	Pass		7754	OSHAWA GATE	2025	$ 4,252,715	Oshawa Gate Station is located on EGI-owned property of approximately 1000 m2 fenced compound in Oshawa, Ontario, approximately 2 km from town, within a rural/urban area, in close proximity to Taunton. This station accepts natural gas from TC Energy and provides supply to 1 XHP network, through components within the Measurement system, Pressure Control system , Heating system, Odourant system, and Telemetry system. This station supplies natural gas to approximately 190,000 customers in the Oshawa Region. The following issues have been identified at this station: Heating System: The existing boilers are undersized for current capacity. Measurement: The current system does not provide measurement of the individual outlet supplies. Visibility to each outlet supply provides greater redundancy to the existing measurement and improved response capabilities. Odourization: The Odourant system was installed in 2011. The current configuration of the Odourant system does not ensure adequate containment of the odourant product in the event of a leak and does not meet the current engineering standards and approvals. Telemetry & Electrical: The existing Electrical system does not meet current EGI electrical installation standards. This poses a potential electrical hazard and faulty wiring may result in lost communications.	Planned							
GTA East	40 - Whitby	Distribution Stations	Pass		7766	DURHAM 23 FEEDER	2024	$ 2,141,268	Durham Road 23 Feeder Station is located on EGI-owned property of approximately 150 m2 fenced compound in the Township of Whitby , Ontario, approximately 3 km east of Ajax, Ontario, within a rural area in proximity to commercial establishments. This station accepts natural gas from EGI XHP and provides supply to an HP network, through components within the Pressure Control system, Heating system, and Telemetry system. This station supplies natural gas to approximately 35,000 customers in Ajax and Whitby areas. The following issues have been identified at this station: Heating: The existing controls on the Heating system have become obsolete, parts are no longer available, and the system is failing to maintain adequate heating requirements. Telemetry & Electrical: The Telemetry and Electrical systems do not meet current EGI standards and are approaching end of useful life. The existing Remoter Terminal Unit (RTU) is obsolete and is required to be upgraded to current standards along with new communications equipment in order to eliminate cybersecurity threats.	Planned							
GTA East	40 - Whitby	Growth	Pass		3740	Area 40 - Apartment Ensuite - New Construction*		$ 640,925	Vertical Subdivision - A multiple unit residential building where each suite is individually metered. Issue/Concern: EGI is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers.	Planned							
GTA East	40 - Whitby	Growth	Pass		3744	Area 40 - Commercial - New Construction*		$ 40,540,507	Issue/Concern: Commercial New Construction refers to a customer intending to run a commercial business in a newly-constructed building and intending to using natural gas to meet energy needs Issue/Concern: EGI is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGI will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGI develops a customer additions forecast using a number of information sources: - Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities - Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates - Projections developed by external consultants specializing in population growth forecasting - Municipal long-term plans: EGI extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report. EGI reviews the following when determining feasibility: - The number of potential new customers - The consumption of natural gas by new customers - The cost of extending the gas main The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGI determines the CIAC amount and communicate with the applicant(s) in writing. Generally, there are three components of capital investments needed to support customer addition requirements: - Installation costs related to mains, services, and meters - Material costs related to mains, services and meters - Costs related to measurement and regulation equipment required to support customer growth. Assets: All applicable assets. Related Program: N/A	Planned							

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Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
GTA East	**40 - Whitby**	Growth	**Pass**		**3747**	Area 40 - Residential - New Construction*		$ 52,089,891	**Issue/Concern: Residential New Construction refers to a new residential construction development of detached single homes constructed by the builder for domestic purposes. Issue/Concern: EGI is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGI will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGI develops a customer additions forecast using a number of information sources: - Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities - Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates - Projections developed by external consultants specializing in population growth forecasting - Municipal long-term plans: EGI extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report. EGI reviews the following when determining feasibility: - The number of potential new customers - The consumption of natural gas by new customers - The cost of extending the gas main The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGI determines the CIAC amount and communicate with the applicant(s) in writing. Generally, there are three components of capital investments needed to support customer addition requirements: - Installation costs related to mains, services, and meters - Material costs related to mains, services and meters - Costs related to measurement and regulation equipment required to support customer growth. Assets: All applicable assets. Related Program: N/A**	Planned							
GTA East	**40 - Whitby**	Growth	**Pass**		**3748**	Area 40 - Residential - Replacement*		$ 62,612,624	**Issue/Concern: Residential Replacement refers to a residential replacement customer using a fuel other than natural gas for domestic purposes and is converting to natural gas. Issue/Concern: EGI is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGI will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGI develops a customer additions forecast using a number of information sources: - Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities - Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates - Projections developed by external consultants specializing in population growth forecasting - Municipal long-term plans: EGI extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report. EGI reviews the following when determining feasibility: - The number of potential new customers - The consumption of natural gas by new customers - The cost of extending the gas main The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGI determines the CIAC amount and communicate with the applicant(s) in writing. Generally, there are three components of capital investments needed to support customer addition requirements: - Installation costs related to mains, services, and meters - Material costs related to mains, services and meters - Costs related to measurement and regulation equipment required to support customer growth. Assets: All applicable assets. Related Program: N/A**	Planned							
GTA East	**40 - Whitby**	Growth	**Pass**		**736524**	NW 4793 Carnwith Dr. Brooklin Reinforcement SRP	**2024**	$ 301,124	**Issue/Concern/Opportunity: Pipe reinforcement of 520 m of NPS 4 PE along Carnwith Dr. W. is required due to system pressures below new minimum allowable system pressure. Assets: Pipe Related Investments: Not applicable**	In Progress							
GTA East	**40 - Whitby**	Growth	**Pass**		**736665**	Station Rebuild 42183A Brock and 3rd Conc SRP	**2023**	$ 218,210	**Issue/Concern/Opportunity: Scope: Station 42183A Rebuild Reinforcement - Pressure regulation upgrades are required to meet the downstream forecasted demands. The reason upgrades are required is to meet capacity requirements to feed network. Assets: District station rebuild Related Program: Not applicable**	Planned							
GTA East	**40 - Whitby**	Utilization	**Pass**		**13546**	MXGI Area 40*	**2019**	$ 33,673,379	**Meters: Meters are used to determine the gas consumption input of customer billing. The replacement program for meters is mandated by Measurement Canada. The program includes: testing, repair, and replacement requirements of meters and instruments. All verified meters are approved by Measurement Canada with an issuance of a certificate which identifies that the meter complies with Electricity and Gas Specification S-EG-02. The Company must ensure all measurement devices remain in compliance for annual audits by Measurement Canada. Measurement Canada specifies tolerances under which the meter must operate in the field. The Company must demonstrate that all aspects of its meter sampling, maintenance, and replacement comply with these criteria in order to be accredited by Measurement Canada to be an "Authorized Service Provider" and adhere to Measurement Canada's accreditation standard S-A-01. Meters may also require exchange for issues such as: damages, leaks, customer billing issues. Regulation: Regulators are the last line of defense for over-pressure to the customer. The condition of regulation systems is determined by regulator performance, corrosion of piping and regulators, and adherence to installation specifications. Failure of the regulation system can cause pressured gas to enter the premise, resulting in failure of gas equipment, loss of containment, and potentially fire or explosion.**	Complete	**Fail**	See investment description, IRPAs not appliable					
GTA West	**20 - Mississauga**	Distribution Pipe	**Fail**	Dollar threshold	**1193**	Erin Mills and Leanne Vital	**2025**	$ 1,513,665									
GTA West	**20 - Mississauga**	Distribution Pipe	**Fail**	Dollar threshold	**7655**	VSM - Bromsgrove Header	**2025**	$ 874,324									
GTA West	**20 - Mississauga**	Distribution Pipe	**Fail**	Dollar threshold	**7656**	VSM - Bramalea and Balmoral Rd	**2023**	$ 830,069									
GTA West	**20 - Mississauga**	Distribution Pipe	**Fail**	Dollar threshold	**8236**	1" ST - Archill Crescent	**2022**	$ 104,083									
GTA West	**20 - Mississauga**	Distribution Pipe	**Fail**	Dollar threshold	**11127**	Copper Service Replacement - Area 20*	**2020**	$ 2,667,645									
GTA West	**20 - Mississauga**	Distribution Pipe	**Fail**	Dollar threshold	**736516**	3665 Flamewood Replacement Copper Relay	**2025**	$ 646,405									
GTA West	**20 - Mississauga**	Distribution Pipe	**Fail**	Emergent Safety	**4661**	Replacement Blanket - Area 20*		$ 4,898,309									
GTA West	**20 - Mississauga**	Distribution Pipe	**Pass**		**4667**	Anode Blanket - Area 20*	**2020**	$ 2,396,036	**General Description: The anodes program within the corrosion program includes the required expenditure to install anodes in order to reduce the amount of down plant within the EGI system. These installations and replacements are based on the Corrosion Operating Standard established to maintain the appropriate level of cathodic protection on steel pipeline assets.**	Complete	**Fail**	See investment description, IRPAs not appliable					
GTA West	**20 - Mississauga**	Distribution Pipe	**Pass**		**4763**	AMP Fitting Replacement - Area 20*	**2020**	$ 83,572,177	**AMP Fittings are a below grade transition fittings. The inserted portion of copper tubing can fail due to internal corrosion. In these cases leaks develop immediately downstream of the AMP Fitting.**	Complete	**Fail**	See investment description, IRPAs not appliable					

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GTA West	**20 - Mississauga**	Distribution Pipe	**Pass**		**7660**	VPM - Erin Township	**2026**	$ 11,695,807	**Issue/Concern: There are site-specific concerns. It has been reported through a leak event that the vintage plastic pipe in Erin Township has experienced cracking due to the stony soil in this area. The Gas Technology Institute (GTI) study on Aldyl A pipe has stated stress intensifier such as rock impingement could result in slow crack growth (SCG) in this type of plastic pipe.** **Assets: Vintage plastic pipe in Erin Township** **Related Programs: Pipe replacement vintage plastic**	Planned							
GTA West	**20 - Mississauga**	Distribution Pipe	**Pass**		**13605**	Service Relay Blanket - Area 20*	**2020**	$ 36,638,282	**General: 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.**	Planned							
GTA West	**20 - Mississauga**	Distribution Pipe	**Pass**		**30114**	Broadway_GTA West_Area 20_1249	**2032**	$ 3,764,887	**Broadway - GTA West - Area 20 - 1249** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
GTA West	**20 - Mississauga**	Distribution Pipe	**Pass**		**30115**	Clarkson Rd 1 - GTA West - Area 20 - 1665	**2029**	$ 2,078,781	**Clarkson Rd. 1 - GTA West - Area 20 - 1665** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: Two projects were created based on regional comments (Clarkson Rd. 1 - 1665 and Clarkson Rd. 2 - 1666).**	Planned							
GTA West	**20 - Mississauga**	Distribution Pipe	**Pass**		**30117**	Elizabeth St S 1 - GTA West - Area 20 - 1667	**2028**	$ 2,830,221	**Elizabeth St. S. 1 - GTA West - Area 20 -1667** **Vintage steel pipes exhibit increased failures as they age, as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: Two projects were created based on regional comments (Elizabeth St. S. 1 – 1667 and Elizabeth St. S. 2 - 1668).**	Planned							
GTA West	**20 - Mississauga**	Distribution Pipe	**Pass**		**30118**	Elizabeth St S 2 - GTA West - Area 20 - 1668	**2032**	$ 3,668,254	**Elizabeth St. S. 2 - GTA West - Area 20 - 1668** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: Two projects were created based on regional comments (Elizabeth St. S. 1 – 1667 and Elizabeth St. S. 2 - 1668)**	Planned							
GTA West	**20 - Mississauga**	Distribution Pipe	**Pass**		**30120**	Gordon St_GTA West_Area 20_1227	**2030**	$ 2,508,009	**Gordon St._GTA West - Area 20 - 1227** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Complete	**Fail**	NPS 2, cannot downsize or retire					
GTA West	**20 - Mississauga**	Distribution Pipe	**Pass**		**30121**	Haggert Ave_GTA West_Area 20_1477	**2031**	$ 4,208,533	**Haggert Ave. - GTA West - Area 20 - 1477** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
GTA West	**20 - Mississauga**	Distribution Pipe	**Pass**		**30122**	Joymar Dr 1 - GTA West - Area 20 - 1670	**2027**	$ 3,195,022	**Joymar Dr. 1 (execute 2024 - road rehabilitation work planned for 2024) - GTA West - Area 20 - 1670** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: Created two projects based on regional comments (Joyman Dr. 1 - 1670 and Joyman Dr. 2 - 1671).**	Complete	**Fail**	NPS 2, cannot downsize or retire					
GTA West	**20 - Mississauga**	Distribution Pipe	**Pass**		**30123**	Joymar Dr 2 - GTA West - Area 20 - 1671	**2027**	$ 3,475,138	**Joymar Dr. 2 - GTA West - Area 20 - 1671** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: Two projects were created based on regional comments (Joyman Dr. 1 - 1670 and Joyman Dr. 2 - 1671).**	Planned							

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GTA West	**20 - Mississauga**	Distribution Pipe	**Pass**		**30125**	Main St_GTA West_Area 20_ 1231	**2030**	$ 4,273,641	**Main St. - GTA West - Area 20 - 1231** **Vintage steel pipes exhibit increased failures as they age, as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
GTA West	**20 - Mississauga**	Distribution Pipe	**Pass**		**30126**	Queen St S 1 - GTA West - Area 20 - 1672	**2031**	$ 2,839,971	**Queen St. S. 1 - GTA West - Area 20 - 1672** **Vintage steel pipes exhibit increased failures as they age, as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: Two projects were created based on regional comments (Queen St. S. 1 - 1672 and Queen St. S. 2 - 1673).**	Planned							
GTA West	**20 - Mississauga**	Distribution Pipe	**Pass**		**30127**	Queen St S 2- GTA West - Area 20 - 1673	**2031**	$ 2,172,774	**Queen St. S. 2 - GTA West - Area 20 - 1673** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: Two projects were created based on regional comments (Queen St. S. 1 - 1672 and Queen St. S. 2 - 1673).**	Planned							
GTA West	**20 - Mississauga**	Distribution Pipe	**Pass**		**30128**	Seagull Dr 1 - GTA West - Area 20 - 1674	**2032**	$ 3,433,839	**Seagull Dr. 1 - GTA West - Area 20 - 1674** **Vintage steel pipes exhibit increased failures as they age, as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: Two projects were created based on regional comments (Seagull Dr. 1 - 1674 and Seagull Dr. 2 - 1675).**	Planned							
GTA West	**20 - Mississauga**	Distribution Pipe	**Pass**		**30129**	Seagull Dr 2 - GTA West - Area 20 - 1675	**2030**	$ 3,657,538	**Seagull Dr. 2 - GTA West - Area 20 - 1675** **Vintage steel pipes exhibit increased failures as they age, as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: Two projects were created based on regional comments (Seagull Dr. 1 - 1674 and Seagull Dr. 2 - 1675).**	Complete	**Fail**	NPS 2, cannot downsize or retire					
GTA West	**20 - Mississauga**	Distribution Pipe	**Pass**		**30130**	Sproule Dr 1 - GTA West - Area 20 - 1676	**2031**	$ 3,915,377	**Sproule Dr. 1 - GTA West - Area 20 - 1676** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: Two projects were created based on regional comments (Sproule Dr. 1 – 1676 and Sproule Dr. 2 - 1677).**	Planned							
GTA West	**20 - Mississauga**	Distribution Pipe	**Pass**		**30131**	Sproule Dr 2 - GTA West - Area 20 - 1677	**2028**	$ 2,502,364	**Sproule Dr. 2 - GTA West - Area 20 - 1677** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: Two projects were created based on regional comments (Sproule Dr. 1 – 1676 and Sproule D.r 2 - 1677).**	Planned							
GTA West	**20 - Mississauga**	Distribution Pipe	**Pass**		**30132**	Vista Dr_GTA West_Area 20_1529	**2032**	$ 4,633,826	**Vista Dr. - GTA West - Area 20 - 1529** **Vintage steel pipes exhibit increased failures as they age, as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
GTA West	**20 - Mississauga**	Distribution Pipe	**Pass**		**102420**	Relocation Program - Area 20*	**2020**	$ 39,569,299	**General: Projects in the relocation category are capital expenditures required to replace or relocate segments of pipeline in order to accommodate municipal infrastructure work. The cost sharing for this work is managed through the Franchise Agreements established with municipalities. A consultative approach is used between the municipality and EGI to avoid conflicts with municipal infrastructure early in the planning stage. If a conflict is unavoidable, pipeline assets are typically relocated or replaced.**	Planned							
GTA West	**20 - Mississauga**	Distribution Stations	**Fail**	Dollar threshold	**7757**	SANDALWOOD GATE	**2027**	$ 489,222									
GTA West	**20 - Mississauga**	Distribution Stations	**Fail**	Dollar threshold	**7781**	EASTGATE AND DIXIE DISTRICT	**2025**	$ 726,894									
GTA West	**20 - Mississauga**	Distribution Stations	**Fail**	Dollar threshold	**18625**	MISSISSAUGA RD & HWY. #7 DISTRICT	**2024**	$ 128,138									
GTA West	**20 - Mississauga**	Distribution Stations	**Fail**	Dollar threshold	**18909**	BRAMALEA & ADVANCE BLVD. DISTRICT	**2026**	$ 156,421									
GTA West	**20 - Mississauga**	Distribution Stations	**Fail**	Dollar threshold	**101119**	21116A - DERRY & HISTORIC TRAIL	**2024**	$ 128,138									
GTA West	**20 - Mississauga**	Distribution Stations	**Fail**	Dollar threshold	**101120**	21102A - BRESLER & AIRPORT	**2024**	$ 128,138									
GTA West	**20 - Mississauga**	Distribution Stations	**Fail**	Dollar threshold	**501491**	Dixie and Derry District	**2023**	$ 62,346									
GTA West	**20 - Mississauga**	Distribution Stations	**Fail**	Dollar threshold	**735174**	20782B DERRY & TOMKEN IP DISTRICT	**2023**	$ 124,691									
GTA West	**20 - Mississauga**	Distribution Stations	**Fail**	Dollar threshold	**735175**	20702A DIXIE & BRITANNIA DISTRICT	**2023**	$ 124,691									

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GTA West	**20 - Mississauga**	Distribution Stations	**Pass**		**1043**	CAWTHRA AND QUEENSWAY DISTRICT	**2024**	$ 2,857,248	**Cawthra and Queensway Feeder Station is located on EGI-owned property of approximately 175 m2 fenced compound in the City of Mississauga, Ontario, within an urban area, within 30 m of residential homes in a densely populated subdivision. This station accepts natural gas from EGI XHP pipeline and provides supply to an IP network, through components within the Pressure Control system, and Telemetry system. This station supplies natural gas to approximately 10,000 customers in the City of Mississauga. The following issues have been identified at this station: Valve & Piping: The piping material and components used within this station have been identified as sub-standard with improper construction methods used during construction. Pressure Control: The configuration of the existing regulators is double boot, posing an undesired higher risk and high associated ongoing maintenance costs. Telemetry & Electrical: The Telemetry and Electrical systems do not meet current EGI standards and are approaching end of useful life. The existing Remote Terminal Unit (RTU) is obsolete and is required to be upgraded to current standards along with new communications equipment in order to eliminate cybersecurity threats. Additionally, new instrumentation, a lighting upgrade, and a tower upgrade which is compliant based on space available is required.**	Planned							
GTA West	**20 - Mississauga**	Distribution Stations	**Pass**		**7777**	WINSTON CHURCHILL AND STEELES FEEDER	**2027**	$ 6,197,593	**Winston Churchill and Steeles Feeder Gate Station is located on EGI-owned property fenced compound in Mississauga, Ontario, approximately 4 km from Meadowvale town centre, within a rural area in close proximity to industrial establishments. This station accepts natural gas from EGI XHP and provides supply to two separate XHP and HP networks, through components within the Pressure Control system, Heating system, and Telemetry system. This station supplies natural gas to approximately 20,000 customers in Mississauga and Brampton area. The following issues have been identified at this station: Telemetry & Electrical: The Telemetry and Electrical systems do not meet current EGI standards, do not contain backup power supply in the event of power loss, and are approaching end of useful life. The existing Remoter Terminal Unit (RTU) is obsolete and is required to be upgraded to current standards along with new communications equipment in order to eliminate cybersecurity threats.**	Planned							
GTA West	**20 - Mississauga**	Distribution Stations	**Pass**		**503369**	Lisgar Station	**2023**	$ 21,527,376	**Issue/Concern/Opportunity: The Lisgar Gate Station is located at a highly populated area in the City of Mississauga. The station is situated in an urban setting and is surrounded by residential buildings, a commercial plaza, and a church. The station has multiple feeds (two transmission lines and one XHP CER line) and various outlets to the local distribution networks. In the event of a major incident, the consequence would be significant given the close proximity to houses and buildings. Justification: The following issues and deficiencies have been identified: Pipes & Valves: They have been deemed unreliable at this site and require removal and installation of new pipes, fittings, and valves. The increased load demand will also allow the pipe to be upsized for current and future expansion. Heating: The Heating system has been deemed unreliable as it has reached its end-of-life cycle usage. The placement of the heat exchangers in the basement of the Boiler building has caused maintenance roadblocks along with flooding concerns. Pressure Regulation: The 20002A regulation has been deemed unreliable and will be rebuilt because of inconsistent flows throughout. The 20002D has suffered from frost-heaving issues as well and requires a rebuild. Odourization: The Odourant system's current configuration does not ensure adequate containment of the odourant product in the event of a leak and does not meet the current engineering standards and approvals. The pumps need automation along with redundancy for better operational efficiency. Building: The Regulator building that houses 20002B and 20002C needs a noise evaluation study to determine a better noise attenuation solution. Measurement: Existing measurement is not reliable and accurate. A more robust and accurate measurement needs to be installed for custody transfer purposes. Assets: Distribution Station Assets at the Lisgar Gate Station. Related Program: AFF - 219 - NPS 24 Lisgar to Pine Valley - permanent launcher support (23192)**	Planned							
GTA West	**20 - Mississauga**	Distribution Stations	**Pass**		**735335**	GTAW Parkway Gate Station Rebuild Phase 2	**2023**	$ 10,598,747	**Project: Parkway East Phase 2. Phase 1 commenced in 2021. Issue/Concern/Opportunity: The following sub-assets will be rebuilt due to the issues described below: Regulators: Two existing Becker control valves, i.e., NPS-8 and NPS-6 downstream operators – PRV-0502 and PRV-0504, Runs 9 and 10 on TC Energy feed (quantity is two) are defective and will not lock up; therefore, replacement is required. Currently, the inlet valve from the TC Energy feed is used to completely shut off the TC Energy feed; otherwise, the control valves will bleed by and affect nominations in the summer, automated TC Energy inlet valve for emergency shutoff from TC Energy, as well as to ensure inlet valve is closed to avoid bleed by of Becker control valves in summer conditions (CLOSE ONLY VALVE). Flow control valves on the TC Energy feed are Fairchild's (will replace with DNGPs – RUNS 9/10) not a computer-controlled regulator and do not sense downstream pressure. Isolation valves for each run are operational. DNGP should also replace Fairchild for 12-inch Union East – CV replacement (12-inch closest to Boiler building - RUN 1); 4th Fairchild is on the MSL – not required – disconnect and replace with VRP pilot (pressure control only due to downstream system operation). The station can be down to facilitate work as system can be fed from Parkway West. An additional five Jordan motors that are obsolete are to be replaced with Rotork motors (quantity is five). Due to capacity constraints and designing for future flow provided by Distribution Optimization Engineering (DOE) / TSP, Run 1 T4 Becker is to be replaced with T1 Becker (NPS 12). Run 3 has undersized isolation valves (currently NPS 8) and will need upsizing to NPS 16. Civil: There is no urethane layer between the pipe support cradle and the bottom of the pipe. A single new Odourant building is required. The wall between the Pressure Transmitter and Remote Terminal Unit (RTU) room is to be opened up for entire building to be RTU room. Demolition of existing Generator building is required. The Storage building is to be removed due to end of life. Piping & Valves: An increase in pipe size near heaters to NPS 30 along with inlet/outlet HX valves to ensure flow requirements can be achieved. Upsizing downstream header and inlet pipe to regulators to NPS 30 is required to ensure it can handle capacity requirements. Odourant: The Odourant system is a metallic odourant building without adequate containment with a rusted containment pan.**	Planned							
GTA West	**20 - Mississauga**	Growth	**Pass**		**3724**	Area 20 - Apartment Traditional - New Construction*		$ 2,059	**Apartment - An apartment customer is a multi-residential dwelling containing more than six units that is bulk-metered. Issue/ Concern: EGI is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers.**	Planned							

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GTA West	**20 - Mississauga**	Growth	**Pass**		**3722**	Area 20 - Apartment Ensuite - New Construction*		$ 3,507,121	**Vertical Subdivision - A multiple unit residential building where each suite is individually metered. Issue/Concern: EGI is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGI will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGI develops a customer additions forecast using a number of information sources: - Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities - Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates - Projections developed by external consultants specializing in population growth forecasting - Municipal long-term plans: EGI extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report. EGI reviews the following when determining feasibility: - The number of potential new customers - The consumption of natural gas by new customers - The cost of extending the gas main The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGI determines the CIAC amount and communicate with the applicant(s) in writing. Generally, there are three components of capital investments needed to support customer addition requirements: - Installation costs related to mains, services, and meters - Material costs related to mains, services and meters - Costs related to measurement and regulation equipment required to support customer growth. Assets: All applicable assets. Related Program: N/A**	Planned							
GTA West	**20 - Mississauga**	Growth	**Pass**		**3726**	Area 20 - Commercial - New Construction*		$ 43,123,319	**Issue/Concern: Commercial New Construction refers to a customer intending to run a commercial business in a newly-constructed building and intending to using natural gas to meet energy needs. Issue/Concern: EGI is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGI will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGI develops a customer additions forecast using a number of information sources: - Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities - Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates - Projections developed by external consultants specializing in population growth forecasting - Municipal long-term plans: EGI extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report. EGI reviews the following when determining feasibility: - The number of potential new customers - The consumption of natural gas by new customers - The cost of extending the gas main The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGI determines the CIAC amount and communicate with the applicant(s) in writing. Generally, there are three components of capital investments needed to support customer addition requirements: - Installation costs related to mains, services, and meters - Material costs related to mains, services and meters - Costs related to measurement and regulation equipment required to support customer growth. Assets: All applicable assets. Related Program: N/A**	Planned							
GTA West	**20 - Mississauga**	Growth	**Pass**		**3729**	Area 20 - Residential - New Construction*		$ 65,585,877	**Issue/Concern: Residential New Construction refers to new residential construction development of detached single homes constructed by the builder for domestic purposes. Issue/Concern: EGI is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGI will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGI develops a customer additions forecast using a number of information sources: - Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities - Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates - Projections developed by external consultants specializing in population growth forecasting - Municipal long-term plans: EGI extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report. EGI reviews the following when determining feasibility: - The number of potential new customers - The consumption of natural gas by new customers - The cost of extending the gas main The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGI determines the CIAC amount and communicate with the applicant(s) in writing. Generally, there are three components of capital investments needed to support customer addition requirements: - Installation costs related to mains, services, and meters - Material costs related to mains, services and meters - Costs related to measurement and regulation equipment required to support customer growth. Assets: All applicable assets. Related Program: N/A**	Planned							

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GTA West	**20 - Mississauga**	Growth	**Pass**		**3730**	Area 20 - Residential - Replacement*		$ 30,865,248	**Issue/Concern: Residential Replacement refers to a residential replacement customer using a fuel other than natural gas for domestic purposes and is converting to natural gas.** **Issue/Concern: EGI is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGI will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGI develops a customer additions forecast using a number of information sources: - Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities - Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates - Projections developed by external consultants specializing in population growth forecasting - Municipal long-term plans: EGI extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report. EGI reviews the following when determining feasibility: - The number of potential new customers - The consumption of natural gas by new customers - The cost of extending the gas main The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGI determines the CIAC amount and communicate with the applicant(s) in writing. Generally, there are three components of capital investments needed to support customer addition requirements: - Installation costs related to mains, services, and meters - Material costs related to mains, services and meters - Costs related to measurement and regulation equipment required to support customer growth.** **Assets: All applicable assets.** **Related Program: N/A**	Planned							
GTA West	**20 - Mississauga**	Growth	**Pass**		**3783**	Area 20 - Commercial - Replacement*		$ 7,028,909	**Issue/Concern: Commercial Replacement refers to a commercial replacement customer using a fuel other than natural gas for commercial business and is converting to natural gas.** **Issue/Concern: EGI is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGI will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGI develops a customer additions forecast using a number of information sources: - Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities - Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates - Projections developed by external consultants specializing in population growth forecasting - Municipal long-term plans: EGI extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report. EGI reviews the following when determining feasibility: - The number of potential new customers - The consumption of natural gas by new customers - The cost of extending the gas main The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGI determines the CIAC amount and communicate with the applicant(s) in writing. Generally, there are three components of capital investments needed to support customer addition requirements: - Installation costs related to mains, services, and meters - Material costs related to mains, services and meters - Costs related to measurement and regulation equipment required to support customer growth.** **Assets: All applicable assets.** **Related Program: N/A**	Planned							
GTA West	**20 - Mississauga**	Growth	**Pass**		**16748**	Erin IP System Reinforcement	**2028**	$ 6,204,820	**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: The purpose of Phase 1 main reinforcement is to provide capacity on the east side of district station RS21100A, Erin District along Main St. and improve the degrading pressures. Phase 2 and 3 will provide capacity and will improve the degrading pressures southwest of the station along Trafalgar Rd.** **• Pressure Issue/Concern: The minimum system pressure is 10 psi and is forecasted to be infeasible by 2019 (when the first phase is proposed to start).** **• Customer Growth Issue/Concern: As of 2018, there are 2,039 customers on this network. Without reinforcement, a forecasted 866 customers may not be able to be added.** **• Risk If Not Completed: At its current condition, the system will not be able to supply gas for large load additions (i.e., subdivision and commercial) as per the Long-Range Plan (LRP) projections since existing mains have limited capacity and pressures below the minimum system pressure. As per model results, in years 2019, 2023, and 2025, pressures were below minimum system pressures.** **Assets (preferred option): Phase 1 Year 2019 - Upsize approximately 2,600 m existing NPS 4 ST/PE to NPS 6 PE on Main St. (Station RS21100A, Erin District to Wellington Rd. 124).** **•2021 Updates: Phases 2 and 3 have been deferred to 2027 and 2028.** **oPhase 2 was deferred to 2027 from 2023 - Upsize approximately 3,100 m existing NPS 4 ST to NPS and PE on Sideroad 17 (Station RS21100A, Erin District to Wellington Rd. 24).** **oPhase 3 was deferred to 2028 from 2025 - Upsize approximately 5,000 m existing NPS 4 ST to NPS and PE on Wellington Rd. 24 (Sideroad 17 to Orangeville St.).**	Planned							

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GTA West	**20 - Mississauga**	Growth	**Pass**		**17243**	NW 2225 Terra Cotta IP Reinforcement SRP	**2028**	$ 1,716,323	**Issue/Concern/Opportunity: 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 Long-Range Plan (LRP) load growth is on the Northwest of the district station RS21221A, King and Creditview District. Because of its collateral impact , the pressures at Mill St. are degraded to below minimum system pressure (MSP) due to less NPS 2 PE main capacity and distance from the NPS 4 PE main source.** **•Pressure Issue/Concern: The minimum system pressure is 10 PSI and was forecasted to be infeasible by 2021. Customer growth issue/concern: In 2017, there are 352 customers on this network. Without reinforcement, forecasted 26 customers (2018-2028) may not be able to be added.** **•Risk if Not Completed: Per model results, pressures on Mill St. will be below the MSP, if the NPS 4 PE main is not installed.** **•Project Benefits: Installing an NPS 4 PE main on Mill St. will mitigate the deteriorating pressures with the projected yearly load growth on the Northwest of the district station RS21221A, King and Creditview District comes in.** **Assets (preferred option):** **•Phase 1 Year 2021 - Install approximately 1,700 m of NPS 4 PE on Mill St. (Creditview Rd. to Mississauga Rd.) .** **•Phase 2 Year 2030 - Install approximately 1,300 m of NPS 4 PE on Mill St. (Mississauga Rd. to Caledon Trailway Path, then along Caledon Trailway Path to Heritage Rd.).** **Assets: Pipe** **Related Program: Not applicable**	Planned							
GTA West	**20 - Mississauga**	Growth	**Pass**		**30500**	NW 2103 Dundalk XHP Reinforcement SRP	**2024**	$ 6,919,435	**NW 2103 Dundalk XHP Reinforcement SRP** **Issue/Concern/Opportunity: Inlet to Ida and Hanbury district station (Dundalk) has dropped below system minimum requirements. Gas volume and flow will be diminished with a potential to limit supply to existing and future customers. There is potential for loss of supply to existing customers during peak period demands.** **Assets: Pipe and district station** **Related Program: Not applicable**	Planned							
GTA West	**20 - Mississauga**	Growth	**Pass**		**30501**	NW 2103 Erin XHP Reinforcement SRP	**2031**	$ 6,265,955	**NW 2103 Erin XHP Reinforcement SRP** **Issue/Concern/Opportunity: Install pipe to improve pressure for downstream station inlet - Network 2103 (i.e., 400 psig system) low pressures modeled at inlet to Erin Stn21100A (74.8psig) in 2030. After Phase 1 reinforcement, the inlet pressure will drop (82 psig) again in 2032.** **Assets: Pipe** **Related Program: Not applicable**	Planned							
GTA West	**20 - Mississauga**	Growth	**Pass**		**30502**	NW 2201 Proton Station IP Reinforcement SRP	**2023**	$ 1,421,859	**NW 2201 Proton Station IP Reinforcement SRP** **Issue/Concern/Opportunity: Existing Intermediate Pressure (IP) system is experiencing very low pressures - 2022 ERX reading low of 5 psig - January 24. Piping system is currently below minimum system requirements and must be improved prior to adding more customers.** **Assets: Pipe** **Related Program: Not applicable**	Planned							
GTA West	**20 - Mississauga**	Utilization	**Pass**		**13544**	MXGI Area 20*	**2019**	$ 73,468,749	**Meters: Meters are used to determine the gas consumption input of customer billing. The replacement program for meters is mandated by Measurement Canada. The program includes: testing, repair, and replacement requirements of meters and instruments. All verified meters are approved by Measurement Canada with an issuance of a certificate which identifies that the meter complies with Electricity and Gas Specification S-EG-02. The Company must ensure all measurement devices remain in compliance for annual audits by Measurement Canada. Measurement Canada specifies tolerances under which the meter must operate in the field. The Company must demonstrate that all aspects of its meter sampling, maintenance, and replacement comply with these criteria in order to be accredited by Measurement Canada to be an "Authorized Service Provider" and adhere to Measurement Canada's accreditation standard S-A-01. Meters may also require exchange for issues such as: damages, leaks, customer billing issues. Regulation: Regulators are the last line of defense for over-pressure to the customer. The condition of regulation systems is determined by regulator performance, corrosion of piping and regulators, and adherence to installation specifications. Failure of the regulation system can cause pressured gas to enter the premise, resulting in failure of gas equipment, loss of containment, and potentially fire or explosion.**	Complete	**Fail**	See investment description, IRPAs not appliable					
GTA West	**50 - Barrie**	Distribution Pipe	**Fail**	Dollar threshold	**4670**	Anode Blanket - Area 50*	**2020**	$ 755,380									
GTA West	**50 - Barrie**	Distribution Pipe	**Fail**	Dollar threshold	**13608**	Service Relay Blanket - Area 50*	**2020**	$ 8,482,187									
GTA West	**50 - Barrie**	Distribution Pipe	**Fail**	Dollar threshold	**30083**	Collier St - Area 50 - 1216	**2032**	$ 1,119,847									
GTA West	**50 - Barrie**	Distribution Pipe	**Fail**	Dollar threshold	**30087**	Main St - Area 50 - 1223	**2031**	$ 1,624,861									
GTA West	**50 - Barrie**	Distribution Pipe	**Fail**	Dollar threshold	**30099**	000071, NRP - Wellington D2 - 1651	**2027**	$ 714,661									
GTA West	**50 - Barrie**	Distribution Pipe	**Fail**	Dollar threshold	**30102**	000724, NRP - HNS Grove B1 - 1605	**2032**	$ 1,561,556									
GTA West	**50 - Barrie**	Distribution Pipe	**Fail**	Dollar threshold	**30104**	Pr#57, NRP - Collins Street - Collingwood - 1614	**2027**	$ 590,028									
GTA West	**50 - Barrie**	Distribution Pipe	**Fail**	Dollar threshold	**30108**	Pr#62, NRP - Cameron Street - Collingwood - 1616	**2029**	$ 685,339									
GTA West	**50 - Barrie**	Distribution Pipe	**Fail**	Dollar threshold	**736572**	Shallow Main - High Street from Dunlop to Park St	**2023**	$ 104,741									
GTA West	**50 - Barrie**	Distribution Pipe	**Fail**	Emergent Safety	**4664**	Replacement Blanket - Area 50		$ 1,135,353									
GTA West	**50 - Barrie**	Distribution Pipe	**Pass**		**4765**	AMP Fitting Replacement - Area 50*	**2020**	$ 13,407,313	**AMP Fittings are a below grade transition fittings. The inserted portion of copper tubing can fail due to internal corrosion. In these cases leaks develop immediately downstream of the AMP Fitting.**	Complete	**Fail**	See investment description, IRPAs not appliable					
GTA West	**50 - Barrie**	Distribution Pipe	**Pass**		**30085**	Ferris Ln - Area 50 - 1201	**2030**	$ 2,848,979	**Ferris Ln. - Area 50 - 1201** **Vintage steel pipes exhibit increased failures as they age, as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
GTA West	**50 - Barrie**	Distribution Pipe	**Pass**		**30086**	Jeffrey St - Area 50 - 1199	**2031**	$ 2,211,627	**Jeffrey St. - Area 50 - 1199** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							

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Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
GTA West	**50 - Barrie**	Distribution Pipe	**Pass**		**30088**	Market St - Area 50 - 1221	**2032**	$ 3,020,905	**Market St - Area 50 - 1221** **Vintage steel pipes exhibit increased failures as they age, as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
GTA West	**50 - Barrie**	Distribution Pipe	**Pass**		**30089**	Oak St 1 - Area 50 - 1654	**2030**	$ 2,219,411	**Oak St. 1 - Area 50 - 1654** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: Two projects were created based on regional comments (Oak St. 1 - Area 50 – 1654 and Oak St. 2 - Area 50 - 1655).**	Planned							
GTA West	**50 - Barrie**	Distribution Pipe	**Pass**		**30091**	Pine St - Area 50 - 1205	**2031**	$ 2,884,425	**Pine St. - Area 50 - 1205** **Vintage steel pipes exhibit increased failures as they age, as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
GTA West	**50 - Barrie**	Distribution Pipe	**Pass**		**30092**	Ross St - Area 50 - 1210	**2028**	$ 2,795,695	**Ross St. - Area 50 - 1210** **Vintage steel pipes exhibit increased failures as they age, as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
GTA West	**50 - Barrie**	Distribution Pipe	**Pass**		**30093**	Second St - Area 50 - 1194	**2032**	$ 3,634,092	**Second St. - Area 50 - 1194** **Vintage steel pipes exhibit increased failures as they age, as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
GTA West	**50 - Barrie**	Distribution Pipe	**Pass**		**30094**	St Paul St - Area 50 - 1220	**2031**	$ 2,485,347	**St. Paul St. - Area 50 - 1220** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
GTA West	**50 - Barrie**	Distribution Pipe	**Pass**		**30097**	Yonge St - Area 50 - 1206	**2032**	$ 3,089,246	**Yonge St - Area 50 - 1206** **Vintage steel pipes exhibit increased failures as they age, as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
GTA West	**50 - Barrie**	Distribution Pipe	**Pass**		**30101**	000715, NRP - Wellington B - 1604	**2032**	$ 2,762,368	**000715, NRP - Wellington B - 2031 - 2033 - 1604** **Vintage steel pipes exhibit increased failures as they age, as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
GTA West	**50 - Barrie**	Distribution Pipe	**Pass**		**30105**	Pr#58, NRP - High Street - Collingwood - 1653	**2030**	$ 2,256,542	**Pr#58, NRP - 2023 - High Street - Collingwood - 1653** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
GTA West	**50 - Barrie**	Distribution Pipe	**Pass**		**30110**	Z1193, NRP - HNS Brock Park B - 1613	**2029**	$ 1,979,712	**Z1193, NRP - HNS Brock Park B, 2024 – 2025 - 1613** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
GTA West	**50 - Barrie**	Distribution Pipe	**Pass**		**30111**	Z74, NRP - HNS Queens Park B - 1652	**2029**	$ 2,507,168	**Z74, NRP - HNS Queens Park B, 2023 – 2025 – 1652** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
GTA West	**50 - Barrie**	Distribution Pipe	**Pass**		**102423**	Relocation Program - Area 50*	**2020**	$ 31,261,154	**General: Projects in the relocation category are capital expenditures required to replace or relocate segments of pipeline in order to accommodate municipal infrastructure work. The cost sharing for this work is managed through the Franchise Agreements established with municipalities. A consultative approach is used between the municipality and EGI to avoid conflicts with municipal infrastructure early in the planning stage. If a conflict is unavoidable, pipeline assets are typically relocated or replaced.**	Planned							
GTA West	**50 - Barrie**	Distribution Stations	**Fail**	Dollar threshold	**21104**	Repeater Sites	**2025**	$ 82,886									

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GTA West	**50 - Barrie**	Distribution Stations	**Pass**		**7756**	RUGBY GATE	**2025**	$ 3,191,800	**Rugby Gate Station is located on EGI-owned property of approximately 1,350 m2 fenced compound in the Township of Oro-Medonte, Ontario, approximately 7 km from Orillia, within a rural area. This station accepts natural gas from TC Energy and provides supply to an XHP network, through components within the Measurement system, Pressure Control system , Heating system, Odourant system, and Telemetry system. This station supplies natural gas to approximately 20,000 customers in the Coldwater, Midland area. The following issues have been identified at this station: Measurement: The current system does not provide measurement of the individual outlet supplies. Visibility to each outlet supply provides greater redundancy to the existing measurement and improved response capabilities. Valve & Piping: The existing piping within this station have been assessed to be in poor corrosion condition with identified degradation of the piping. HEATING: the existing boilers at this site are 16 years old, they have had 5 trouble call/failures over the past year including failures of the motors and pumps, burner lock-outs and exchanger failures. Due to recent and upcoming customer growth in the Barrie area, the existing Heating system will not be capable of supplying the heating requirements to meet the demand. Odourization: The Odourant system was installed in 2003. The current configuration of the Odourant system does not ensure adequate containment of the odourant product in the event of a leak and does not meet the current engineering standards and approvals. Telemetry & Electrical: The existing Electrical system does not meet current EGI electrical installation standards. This poses a potential electrical hazard and faulty wiring may result in lost communications. Compliance: The existing Boiler building is located within a hazardous area and will have to be relocated.**	Planned							
GTA West	**50 - Barrie**	Distribution Stations	**Pass**		**7758**	THORNTON GATE	**2024**	$ 4,656,346	**Pipe, Valves & Others: Minor station piping is required for this project scope. The existing Piping and Valve system is in good shape. Due to the reconfiguration for the Heating system, minor station piping may be required to align the new equipment. Issue/Concern: Heating System: Updated heating is required at this station. A new heat exchanger is required including the associated piping for the glycol inlet and outlet to the heating element. New boilers can fit within the limits of the existing building. New modulating boilers are required. Pressure Control: New regulation is required to various flow ranges. New Becker regulators and two runs are required. One monitor and one operator is needed for two runs. This will involve new spools for both runs at a minimum. Odourant System: No changes are required. Telemetry/Electrical: New Control Wave Micro unit and associated connections are required. One new pressure transmitter and one new temperature transmitter are to be accounted for. Measurement: Annubar is sized correct. There is no requirement for replacement. Building: A new Remote Terminal Unit (RTU) building is required (concrete pre-cast building). The existing RTU building is to be removed. Compliance/Civil: Site grading will be required as well as new security fencing (galvanized) including new swing gate and crash bar access. Scope: Heating System: Updated heating is required at this station. New Heat Exchanger is required including the associated piping for the glycol inlet and outlet to heating element. New boilers can fit within the limits of the existing building. New modulating boilers are required. Pressure Control: New Regulation required to various flow ranges. New Becker regulators are 2 Run's are required. 1 Monitor and 1 operator is needed for 2 runs. This will involve new spools for both runs at a minimum. Odorant System: No changes required Telemetry/Electrical: New Control Wave Micro unit required and associated connections. Account for 1 new pressure transmitter and 1 new temperature transmitter. Measurement: Annubar is sized correct. No requirement for replacement.**	Planned							
GTA West	**50 - Barrie**	Growth	**Pass**		**3753**	Area 50 - Commercial - New Construction*		$ 11,233,172	**Issue/Concern: Commercial New Construction refers to a customer intending to run a commercial business in a newly-constructed building and intending to using natural gas to meet energy needs Issue/Concern: EGI is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGI will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGI develops a customer additions forecast using a number of information sources: - Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities - Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates - Projections developed by external consultants specializing in population growth forecasting - Municipal long-term plans: EGI extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report. EGI reviews the following when determining feasibility: - The number of potential new customers - The consumption of natural gas by new customers - The cost of extending the gas main The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGI determines the CIAC amount and communicate with the applicant(s) in writing. Generally, there are three components of capital investments needed to support customer addition requirements: - Installation costs related to mains, services, and meters - Material costs related to mains, services and meters - Costs related to measurement and regulation equipment required to support customer growth. Assets: All applicable assets. Related Program: N/A**	Planned							

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GTA West	50 - Barrie	Growth	Pass		3756	Area 50 - Residential - New Construction*		$ 89,321,709	Issue/Concern: Residential New Construction refers to a new residential construction development of detached single homes constructed by the builder for domestic purposes. Issue/Concern: EGI is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGI will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGI develops a customer additions forecast using a number of information sources: - Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities - Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates - Projections developed by external consultants specializing in population growth forecasting - Municipal long-term plans: EGI extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report. EGI reviews the following when determining feasibility: - The number of potential new customers - The consumption of natural gas by new customers - The cost of extending the gas main The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGI determines the CIAC amount and communicate with the applicant(s) in writing. Generally, there are three components of capital investments needed to support customer addition requirements: - Installation costs related to mains, services, and meters - Material costs related to mains, services and meters - Costs related to measurement and regulation equipment required to support customer growth. Assets: All applicable assets. Related Program: N/A	Planned							
GTA West	50 - Barrie	Growth	Pass		3757	Area 50 - Residential - Replacement*		$ 61,102,549	Issue/Concern: Residential Replacement refers to a residential replacement customer using a fuel other than natural gas for domestic purposes and is converting to natural gas. Issue/Concern: EGI is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGI will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGI develops a customer additions forecast using a number of information sources: - Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities - Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates - Projections developed by external consultants specializing in population growth forecasting - Municipal long-term plans: EGI extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report. EGI reviews the following when determining feasibility: - The number of potential new customers - The consumption of natural gas by new customers - The cost of extending the gas main The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGI determines the CIAC amount and communicate with the applicant(s) in writing. Generally, there are three components of capital investments needed to support customer addition requirements: - Installation costs related to mains, services, and meters - Material costs related to mains, services and meters - Costs related to measurement and regulation equipment required to support customer growth. Assets: All applicable assets. Related Program: N/A	Planned							
GTA West	50 - Barrie	Growth	Pass		30503	NW 5346 Midhurst Reinforcement SRP	2024	$ 1,334,348	NW 5346 Midhurst Reinforcement SRP Issue/Concern/Opportunity: Total of 1,300 m NPS 4 is required to increase security of supply for Midhurst, and maintain 140 kPa as Minimum System Pressure in this Maximum Operating Pressure (MOP) 345 kPa system. Assets: Pipe Related Program: Not applicable	Planned							
GTA West	50 - Barrie	Growth	Pass		30504	NW 5446 Hwy 26 and Keith Reinforcement SRP	2024	$ 750,550	NW 5446 Hwy 26 and Keith Reinforcement SRP Issue/Concern/Opportunity: A new station and total 420 m NPS 4 are required to increase security of supply for Intermediate Pressure (IP) NW5446/5372. Existing station #3362255 cannot maintain the system health and a damage occurred on November 1, 2021. Assets: Pipe and district station Related Program: Not applicable	Planned							
GTA West	50 - Barrie	Growth	Pass		30505	NW 5422 Robins Point Rd. Reinforcement SRP	2024	$ 717,957	NW 5422 Robins Point Rd. Reinforcement SRP Issue/Concern/Opportunity: A total of 800 m NPS 2 is required to increase security of supply for Victoria Harbour, and maintain 140 kPa as minimum system pressure in this Maximum Operating Pressure (MOP) 310 kPa system. In January 2022, 13 psig was recorded as low pressure in cold snap. Assets: Pipe Related Program: Not applicable	Planned							
GTA West	50 - Barrie	Growth	Pass		500705	NW 5301 Barrie - Collingwood Pressure Increase SRP	2022	$ 1,496,294	Issue/Concern/Opportunity: Pressure issue is at the west tail end of network 5301. The long-range planning forecast shows by 2024 that the pressure will drop below 100 psig. Recently, a few customer load addition requests have been denied based on a diminished pressure and capacity constraint. Currently, the Maximum Operating Pressure in Network 5301 is 400 psig and this pressure elevation is looking to increase it to 500 psig. •With this pressure elevation, current new customers can be accommodated quickly. •With this pressure elevation, County Rd. 9 reinforcement can be deferred to 10 years later. •Preparation for next steps can happen to harmonize Barrie to Collingwood line with Rugby XHP system, by pressure increase on Rugby Gate Station, from 480 psig to 500 psig and removing Rugby Kicker Station. •By harmonizing these two systems, Penetanguishine Reinforcement project ($15.2M – BC#7723) can be deferred to 10 years later. Assets: All pipe and stations on Network 5301 will be assessed if any reinforcements need to be made. Related Program: Not applicable.	Planned							

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Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
GTA West	50 - Barrie	Utilization	Pass		13547	MXGI Area 50*	2019	$ 16,833,109	Meters: Meters are used to determine the gas consumption input of customer billing. The replacement program for meters is mandated by Measurement Canada. The program includes: testing, repair, and replacement requirements of meters and instruments. All verified meters are approved by Measurement Canada with an issuance of a certificate which identifies that the meter complies with Electricity and Gas Specification S-EG-02. The Company must ensure all measurement devices remain in compliance for annual audits by Measurement Canada. Measurement Canada specifies tolerances under which the meter must operate in the field. The Company must demonstrate that all aspects of its meter sampling, maintenance, and replacement comply with these criteria in order to be accredited by Measurement Canada to be an "Authorized Service Provider" and adhere to Measurement Canada's accreditation standard S-A-01. Meters may also require exchange for issues such as: damages, leaks, customer billing issues. Regulation: Regulators are the last line of defense for over-pressure to the customer. The condition of regulation systems is determined by regulator performance, corrosion of piping and regulators, and adherence to installation specifications. Failure of the regulation system can cause pressured gas to enter the premise, resulting in failure of gas equipment, loss of containment, and potentially fire or explosion.	Complete	Fail	See investment description, IRPAs not appliable					
GTA West	Div_17 - Halton	Distribution Pipe	Fail	Dollar threshold	48454	HALT: Dist-Repl-Contr-Mains Leakage*	2019	$ 1,377,825									
GTA West	Div_17 - Halton	Distribution Pipe	Fail	Dollar threshold	48455	HALT: Dist-Repl-Contr-Services*	2020	$ 10,347,400									
GTA West	Div_17 - Halton	Distribution Pipe	Fail	Dollar threshold	503061	Halt: Harrop drive, Milton, BU Replacement	2024	$ 710,529									
GTA West	Div_17 - Halton	Distribution Pipe	Pass		48453	HALT: Dist-Repl-Contr-Mains Municipal*	2020	$ 38,392,868	General: Projects in the relocation category are capital expenditures required to replace or relocate segments of pipeline in order to accommodate municipal infrastructure work. The cost sharing for this work is managed through the Franchise Agreements established with municipalities. A consultative approach is used between the municipality and EGI to avoid conflicts with municipal infrastructure early in the planning stage. If a conflict is unavoidable, pipeline assets are typically relocated or replaced.	Planned							
GTA West	Div_17 - Halton	Distribution Pipe	Pass		503196	HALT: Anodes*	2020	$ 5,858,459	General: The anodes program within the corrosion program includes the required expenditure to install anodes in order to reduce the amount of down plant within EGI's 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.	Complete	Fail	See investment description, IRPAs not appliable					
GTA West	Div_17 - Halton	Distribution Stations	Fail	Dollar threshold	101081	HALT-Winston Churchill & 10 Side Rd	2025	$ 645,725									
GTA West	Div_17 - Halton	Distribution Stations	Fail	Dollar threshold	101085	HALT-Lynden Gate Stn	2025	$ 645,725									
GTA West	Div_17 - Halton	Distribution Stations	Fail	Dollar threshold	101088	HALT-Third Line and QEW Vault Station	2025	$ 645,725									
GTA West	Div_17 - Halton	Distribution Stations	Fail	Dollar threshold	101089	HALT-Milton TBS	2025	$ 1,291,450									
GTA West	Div_17 - Halton	Distribution Stations	Fail	Dollar threshold	101096	HALT - York and Broadway	2028	$ 688,087									
GTA West	Div_17 - Halton	Distribution Stations	Fail	Dollar threshold	101099	HALT - Dundas and Meadowridge	2025	$ 516,580									
GTA West	Div_17 - Halton	Distribution Stations	Fail	Dollar threshold	101125	HALT - Centennial and Guelph Line Vault Station	2023	$ 622,765									
GTA West	Div_17 - Halton	Distribution Stations	Fail	Dollar threshold	735035	Halt: Ninth/Britannia, Rebuild	2024	$ 640,809									
GTA West	Div_17 - Halton	Distribution Stations	Fail	Dollar threshold	735039	HALT: Ford and Royal Windsor, Maintenance	2025	$ 516,580									
GTA West	Div_17 - Halton	Distribution Stations	Fail	Dollar threshold	735049	HALT: EC Drury School,Rebuild	2030	$ 70,737									
GTA West	Div_17 - Halton	Distribution Stations	Fail	Dollar threshold	735052	HALT: Saputo, rebuild	2026	$ 260,645									
GTA West	Div_17 - Halton	Distribution Stations	Fail	Dollar threshold	735055	HALT: Morgan Thermal Ceramics, Maintenance	2030	$ 70,737									
GTA West	Div_17 - Halton	Distribution Stations	Fail	Dollar threshold	735066	HALT: Affinia Canada Corp, Rebuild	2032	$ 271,598									
GTA West	Div_17 - Halton	Distribution Stations	Fail	Dollar threshold	735067	HALT: Milton Hydro Dist Inc, Rebuild	2030	$ 282,950									
GTA West	Div_17 - Halton	Distribution Stations	Pass		735054	HALT: Burlington Gate, boiler	2028	$ 2,752,350	Issue/Concern/Opportunity: VALVE & PIPING: Piping is experiencing corrosion and will be evaluated by FIMP closer to the proposed project date. FIMP will asses the existing valves for any iissues in performance and operation. FILTRATION: N/A HEATING: the existing boilers at this site have reached end of life based on condition review and performance. The building is in disrepair and will be replaced in this investment. This investment aligns with the obsolete heating system strategy that 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, including providing the appropriate containment systems to minimize the impacts of an event. Loss of the heating system function could result in two scenarios, (1) frost heave or (2) pressure control failure due to the freezing of station components. Frost heave occurs when the gas is cooled due to the pressure reduction and causes an upward swelling of soil around public or private property near the gas main. Freezing of station components such as creating large ice buildup around valves can prevent operation if gas isolation is required. This could result in the loss of pressure control and potentially lead to an overpressure or underpressure situation. 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. PRESSURE CONTROL: Obsolete design will be replaced in this investment. ODOURIZATION: Current system is in working order. TELEMETRY & ELECTRICAL: the telemetry and electrical systems do not meet current EGI standards, do not contain backup power supply in the event of powerloss, and are approaching end of useful life. MEASUREMENT . COMPLIANCE & OTHER Eng: will be assessed closer to project date. Signage and site assess (fencing/egress) to be	Planned							
GTA West	Div_17 - Halton	Growth	Pass		48452	HALT: Company Program - New Business - Scattered Mains - Contractor*	2020	$ 37,840,249	Scattered Mains	Planned							
GTA West	Div_17 - Halton	Growth	Pass		500422	HALT: Company Program - Customer Connections*		$ 40,491,554	Hamilton Customer Connections Program Items	Planned							
GTA West	Div_17 - Halton	Growth	Pass		503058	SRP_GTA West_Oakville_18Y-109RSTN_Rebuild	2023	$ 1,307,807	Growth in the Old Bronte/Khalsa gate area of Oakville requires a new station to be built. This is a placeholder for the station, land and installation cost.	Planned							
GTA West	Div_17 - Halton	Growth	Pass		735034	SRP_GTA West_Lowville_18X-101STN_Rebuild	2024	$ 897,133	Issue/Concern/Opportunity: Single feed to Campbellville, no filter, requires operator monitor, heater undersized, and no filtration. The scope is to build a monitor-operator system, upgrade regulation, install Remote Terminal Unit (RTU) and replace heater.	Planned							
GTA West	Div_17 - Halton	Utilization	Pass		48464	HALT: Meter & Regulator Inst Repl-Contractor	2020	$ 33,814,150	Meter & Reg Install- Replacement	Complete	Fail	See investment description, IRPAs not appliable					
Head Office Support	Div_54 - Head Office Support	Distribution Pipe	Fail	Dollar threshold	1180	Integrity Capital Tools Program*		$ 509,611									
Head Office Support	Div_54 - Head Office Support	Distribution Pipe	Fail	Dollar threshold	1905	2026 Integrity Program*		$ 387,435									
Head Office Support	Div_54 - Head Office Support	Distribution Pipe	Fail	Dollar threshold	49651	Mattawa Bridge - North Bay 18	2023	$ 952,831									
Head Office Support	Div_54 - Head Office Support	Distribution Pipe	Fail	Dollar threshold	100091	Corrosion Program Rectifier Groundbed*	2030	$ 4,145,202									
Head Office Support	Div_54 - Head Office Support	Distribution Pipe	Fail	Timing	1278	2023 Integrity Dig Program*	2023	$ 13,514,004				Within 3 years, supply side not applicable					
Head Office Support	Div_54 - Head Office Support	Distribution Pipe	Fail	Timing	1287	2024 Integrity Dig Program*	2024	$ 10,989,876				Within 3 years, supply side not applicable					

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Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
Head Office Support	**Div_54 - Head Office Support**	Distribution Pipe	**Fail**	Timing	**1291**	2025 Integrity Retrofit Program*	**2025**	$ 3,874,351				Within 3 years, supply side not applicable					
Head Office Support	**Div_54 - Head Office Support**	Distribution Pipe	**Fail**	Timing	**1294**	2025 Integrity Dig Program*	**2025**	$ 8,136,136				Within 3 years, supply side not applicable					
Head Office Support	**Div_54 - Head Office Support**	Distribution Pipe	**Fail**	Timing	**102450**	2023 Class Location Replacement Program*	**2023**	$ 1,245,530				Within 3 years, supply side not applicable					
Head Office Support	**Div_54 - Head Office Support**	Distribution Pipe	**Fail**	Timing	**102451**	2024 Class Location Replacement Program*	**2024**	$ 2,563,237				Within 3 years, supply side not applicable					
Head Office Support	**Div_54 - Head Office Support**	Distribution Pipe	**Fail**	Timing	**102452**	2025 Class Location Replacement Program*	**2025**	$ 2,582,900				Within 3 years, supply side not applicable					
Head Office Support	**Div_54 - Head Office Support**	Distribution Pipe	**Fail**	Timing	**736419**	2023 DP Depth of Cover Mitigation Program*	**2023**	$ 7,473,182				Within 3 years, supply side not applicable					
Head Office Support	**Div_54 - Head Office Support**	Distribution Pipe	**Pass**		**1276**	2023 Integrity Retrofit Program*		$ 3,736,591	**Project Specific: Integrity Retrofit program, supporting refinement of pipeline risk profile. The purpose of this program is to gain a more complete level of pipeline risk by making additional pipelines accessible for Inline Inspection. Specific pipelines for retrofit will be identified 1-2 years prior to year of construction. 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 inline 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 that are identified through the inspections.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office Support	**Div_54 - Head Office Support**	Distribution Pipe	**Pass**		**1284**	2024 Integrity Retrofit Program*		$ 3,844,855	**Project Specific: Integrity Retrofit program, supporting refinement of pipeline risk profile. The purpose of this program is to gain a more complete level of pipeline risk by making additional pipelines accessible for Inline Inspection. 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 EGIs 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 inline 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 that are identified through the inspections.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office Support	**Div_54 - Head Office Support**	Distribution Pipe	**Pass**		**49935**	Depth of Cover Mitigation Program*	**2028**	$ 19,612,549	**General: In compliance with the TSSA Code Adoption Document, EGI has an annual depth of cover survey program for all 30 per cent 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 required remediation.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office Support	**Div_54 - Head Office Support**	Distribution Pipe	**Pass**		**49938**	MOP Verification Replacement Program*	**2029**	$ 51,256,031	**Maximum Operating Pressure (MOP) verification is the process of reviewing all existing records for a pipeline system and confirming the maximum operating pressure of pipelines that are greater than 30 percent 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 the number of pipelines greater than 30 percent SMYS, MOP verification will continue to be a multi-year project requiring a dedicated team to complete the verifications and determine if any pipeline remediation is required. This forecast includes the costs of replacing sections of pipelines as identified through the MOP verification work. MOP verification was also included in the 2017 customer engagement survey: while 43 per cent of those surveyed recommend waiting for regulation requirements to keep costs down, 40 per cent recommend proactively implementing industry standard. Spreading the verifications over several years will keep costs down and proactively implement an industry standard, which provides additional support for this program. Starting this program as forecast will mitigate the need for higher expenditures in a shorter time frame to meet these expected future mandated requirements.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office Support	**Div_54 - Head Office Support**	Distribution Pipe	**Pass**		**102453**	2026 Class Location Replacement Program*	**2034**	$ 6,516,114	**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, 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 in order to meet the 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.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office Support	**Div_54 - Head Office Support**	Distribution Pipe	**Pass**		**102454**	2027 Class Location Replacement Program*	**2035**	$ 6,938,715	**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, 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 in order to meet the 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.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office Support	**Div_54 - Head Office Support**	Distribution Pipe	**Pass**		**102455**	2028 Class Location Replacement Program*	**2036**	$ 6,880,875	**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, 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 in order to meet the 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.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office Support	**Div_54 - Head Office Support**	Distribution Pipe	**Pass**		**102456**	2029 Class Location Replacement Program*	**2037**	$ 6,831,606	**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, 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 in order to meet the 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.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office Support	**Div_54 - Head Office Support**	Distribution Pipe	**Pass**		**102457**	2030 Class Location Replacement Program*	**2038**	$ 7,073,747	**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, 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 in order to meet the 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.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office Support	**Div_54 - Head Office Support**	Distribution Pipe	**Pass**		**102744**	2026 Integrity Dig Program*		$ 10,145,589	**Forecast: not provided for 2026-2030 at this time, using average of 2020-2025 as placeholder 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 inline 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 that are identified through the inspections.**	Complete	**Fail**	See investment description, IRPAs not appliable					

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Head Office Support	**Div_54 - Head Office Support**	Distribution Pipe	**Pass**		**102746**	2027 Integrity Dig Program*		$ 10,803,579	**Forecast: not provided for 2026-2030 at this time, using average of 2020-2025 as placeholder 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 inline 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 that are identified through the inspections.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office Support	**Div_54 - Head Office Support**	Distribution Pipe	**Pass**		**102747**	2028 Integrity Dig Program*		$ 10,713,522	**Forecast: not provided for 2026-2030 at this time, using average of 2020-2025 as placeholder 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 inline 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 that are identified through the inspections.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office Support	**Div_54 - Head Office Support**	Distribution Pipe	**Pass**		**102748**	2029 Integrity Dig Program*		$ 10,636,811	**Forecast: not provided for 2026-2030 at this time, using average of 2020-2025 as placeholder 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 inline 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 that are identified through the inspections.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office Support	**Div_54 - Head Office Support**	Distribution Pipe	**Pass**		**102750**	2030 Integrity Dig Program*		$ 11,013,824	**Forecast: not provided for 2026-2032 at this time, using average of 2020-2025 as placeholder 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 inline 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 that are identified through the inspections.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office Support	**Div_54 - Head Office Support**	Distribution Pipe	**Pass**		**102751**	2026 Integrity Retrofit Program*		$ 4,300,635	**Project Specific: Forecast note provided for 2026-2030, using average of 2023-2025 as placeholder. 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 inline 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 that are identified through the inspections.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office Support	**Div_54 - Head Office Support**	Distribution Pipe	**Pass**		**102752**	2027 Integrity Retrofit Program*		$ 4,579,552	**Project Specific: Forecast note provided for 2026-2030, using average of 2023-2025 as placeholder. 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 inline 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 that are identified through the inspections.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office Support	**Div_54 - Head Office Support**	Distribution Pipe	**Pass**		**102753**	2028 Integrity Retrofit Program*		$ 4,541,377	**Project Specific: Forecast note provided for 2026-2030, using average of 2023-2025 as placeholder. 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 inline 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 that are identified through the inspections.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office Support	**Div_54 - Head Office Support**	Distribution Pipe	**Pass**		**102754**	2029 Integrity Retrofit Program*		$ 4,508,860	**Project Specific: Forecast note provided for 2026-2030, using average of 2023-2025 as placeholder. 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 inline 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 that are identified through the inspections.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office Support	**Div_54 - Head Office Support**	Distribution Pipe	**Pass**		**102755**	2030 Integrity Retrofit Program*		$ 4,668,673	**Project Specific: Forecast note provided for 2026-2032, using average of 2023-2025 as placeholder. 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 inline 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 that are identified through the inspections.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office Support	**Div_54 - Head Office Support**	Distribution Pipe	**Pass**		**503431**	Bridge Crossing Painting Program*		$ 6,465,631	**Issue/Concern/Opportunity: Bridge crossing inspection results in different levels of action which can include replacement, recoating, or hanger repair/replacement work. This program is for recoating work and hanger repair. Justification: The integrated Corrosion Operating Standard ST-17-B13A-DDA9 was released 2020-11-25 and requires the following surveys: Annual visual, 5 year detailed. The standard outlines the following time frames: Bridge crossing – replace Per Engineering assessment per project plan; Bridge crossing – replace expansion joint / Ins flange within 24 months; Bridge crossing / paint pipe / repair hangers / replace casing end seal within 12 months. Assets: Related Investments:**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office Support	**Div_54 - Head Office Support**	Distribution Pipe	**Pass**		**733983**	2031 Class Location Replacement Program*	**2039**	$ 6,996,393	**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, 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 in order to meet the 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.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office Support	**Div_54 - Head Office Support**	Distribution Pipe	**Pass**		**733984**	2032 Class Location Replacement Program*	**2040**	$ 6,789,956	**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, 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 in order to meet the 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.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office Support	**Div_54 - Head Office Support**	Distribution Pipe	**Pass**		**733990**	2031 Integrity Dig Program*		$ 10,893,384	**Forecast: not provided for 2026-2032 at this time, using average of 2020-2025 as placeholder 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 inline 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 that are identified through the inspections.**	Complete	**Fail**	See investment description, IRPAs not appliable					

* in the Investment Name indicates a program item. Program items are unique as they represent numerous projects grouped together and budgeted in advance. This results in forecast spend appearing larger than it would at the project level and it also impacts the in-service dates

Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
Head Office Support	**Div_54 - Head Office Support**	Distribution Pipe	**Pass**		**733992**	2032 Integrity Dig Program*		$ 10,571,962	**Forecast: not provided for 2026-2032 at this time, using average of 2020-2025 as placeholder 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 inline 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 that are identified through the inspections.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office Support	**Div_54 - Head Office Support**	Distribution Pipe	**Pass**		**733996**	2031 Integrity Retrofit Program*		$ 4,617,619	**Project Specific: Forecast note provided for 2026-2032, using average of 2023-2025 as placeholder. 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 inline 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 that are identified through the inspections.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office Support	**Div_54 - Head Office Support**	Distribution Pipe	**Pass**		**733997**	2032 Integrity Retrofit Program*		$ 4,481,371	**Project Specific: Forecast note provided for 2026-2032, using average of 2023-2025 as placeholder. 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 inline 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 that are identified through the inspections.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office Support	**Div_54 - Head Office Support**	Distribution Stations	**Fail**	Dollar threshold	**49612**	CFB Station Retirement	**2032**	$ 135,799									
Head Office Support	**Div_54 - Head Office Support**	Distribution Stations	**Fail**	Dollar threshold	**102667**	2023 Odourant Upgrades - MOIS Upgrades*	**2023**	$ 1,245,530									
Head Office Support	**Div_54 - Head Office Support**	Distribution Stations	**Fail**	Dollar threshold	**102680**	2023 Odourant Upgrades -Sweep Tanks*	**2023**	$ 373,659									
Head Office Support	**Div_54 - Head Office Support**	Distribution Stations	**Fail**	Dollar threshold	**102681**	2024 Odourant Upgrades -Sweep Tanks*	**2024**	$ 384,485									
Head Office Support	**Div_54 - Head Office Support**	Distribution Stations	**Fail**	Dollar threshold	**102683**	2025 Odourant Upgrades -Sweep Tanks*	**2025**	$ 387,435									
Head Office Support	**Div_54 - Head Office Support**	Distribution Stations	**Fail**	Dollar threshold	**102721**	2023 Odourant Upgrades - Disposal/Decommission*	**2023**	$ 49,821									
Head Office Support	**Div_54 - Head Office Support**	Distribution Stations	**Fail**	Dollar threshold	**102722**	2024 Odourant Upgrades - Disposal/Decommission*	**2024**	$ 51,265									
Head Office Support	**Div_54 - Head Office Support**	Distribution Stations	**Fail**	Dollar threshold	**102723**	2025 Odourant Upgrades - Disposal/Decommission*	**2025**	$ 51,658									
Head Office Support	**Div_54 - Head Office Support**	Distribution Stations	**Fail**	Dollar threshold	**102736**	2023 Turbine Meter Automatic Oilers Upgrade	**2023**	$ 103,409									
Head Office Support	**Div_54 - Head Office Support**	Distribution Stations	**Fail**	Dollar threshold	**102737**	2024 Turbine Meter Automatic Oilers Upgrade	**2024**	$ 108,533									
Head Office Support	**Div_54 - Head Office Support**	Distribution Stations	**Fail**	Dollar threshold	**102738**	2025 Turbine Meter Automatic Oilers Upgrade	**2025**	$ 111,553									
Head Office Support	**Div_54 - Head Office Support**	Distribution Stations	**Fail**	Dollar threshold	**735219**	2026 Odourant Upgrades -Sweep Tanks*	**2026**	$ 390,967									
Head Office Support	**Div_54 - Head Office Support**	Distribution Stations	**Fail**	Dollar threshold	**735220**	2027 Odourant Upgrades -Sweep Tanks*	**2027**	$ 416,323									
Head Office Support	**Div_54 - Head Office Support**	Distribution Stations	**Fail**	Dollar threshold	**735221**	2028 Odourant Upgrades -Sweep Tanks*	**2028**	$ 412,852									
Head Office Support	**Div_54 - Head Office Support**	Distribution Stations	**Fail**	Dollar threshold	**735222**	2029 Odourant Upgrades -Sweep Tanks*	**2029**	$ 409,896									
Head Office Support	**Div_54 - Head Office Support**	Distribution Stations	**Fail**	Dollar threshold	**735223**	2030 Odourant Upgrades -Sweep Tanks*	**2030**	$ 424,425									
Head Office Support	**Div_54 - Head Office Support**	Distribution Stations	**Fail**	Dollar threshold	**735224**	2031 Odourant Upgrades -Sweep Tanks*	**2031**	$ 419,784									
Head Office Support	**Div_54 - Head Office Support**	Distribution Stations	**Fail**	Dollar threshold	**735225**	2032 Odourant Upgrades -Sweep Tanks*	**2032**	$ 407,397									
Head Office Support	**Div_54 - Head Office Support**	Distribution Stations	**Fail**	Dollar threshold	**735227**	2026 Odourant Upgrades - Disposal/Decommission*	**2026**	$ 52,129									
Head Office Support	**Div_54 - Head Office Support**	Distribution Stations	**Fail**	Dollar threshold	**735228**	2027 Odourant Upgrades - Disposal/Decommission*	**2027**	$ 55,510									
Head Office Support	**Div_54 - Head Office Support**	Distribution Stations	**Fail**	Dollar threshold	**735230**	2028 Odourant Upgrades - Disposal/Decommission*	**2028**	$ 55,047									
Head Office Support	**Div_54 - Head Office Support**	Distribution Stations	**Fail**	Dollar threshold	**735231**	2029 Odourant Upgrades - Disposal/Decommission*	**2029**	$ 54,653									
Head Office Support	**Div_54 - Head Office Support**	Distribution Stations	**Fail**	Dollar threshold	**735232**	2030 Odourant Upgrades - Disposal/Decommission*	**2030**	$ 56,590									
Head Office Support	**Div_54 - Head Office Support**	Distribution Stations	**Fail**	Dollar threshold	**735233**	2031 Odourant Upgrades - Disposal/Decommission*	**2031**	$ 55,971									
Head Office Support	**Div_54 - Head Office Support**	Distribution Stations	**Fail**	Dollar threshold	**735234**	2032 Odourant Upgrades - Disposal/Decommission*	**2032**	$ 54,320									
Head Office Support	**Div_54 - Head Office Support**	Distribution Stations	**Fail**	Dollar threshold	**735236**	2026Turbine Meter Automatic Oilers Upgrade	**2026**	$ 114,822									
Head Office Support	**Div_54 - Head Office Support**	Distribution Stations	**Fail**	Dollar threshold	**735237**	2027 Turbine Meter Automatic Oilers Upgrade	**2027**	$ 124,714									

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Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
Head Office Support	**Div_54 - Head Office Support**	Distribution Stations	**Fail**	Dollar threshold	**735238**	2028 Turbine Meter Automatic Oilers Upgrade	**2028**	$ 126,147									
Head Office Support	**Div_54 - Head Office Support**	Distribution Stations	**Fail**	Dollar threshold	**735240**	2029 Turbine Meter Automatic Oilers Upgrade	**2029**	$ 127,748									
Head Office Support	**Div_54 - Head Office Support**	Distribution Stations	**Fail**	Dollar threshold	**735241**	2030 Turbine Meter Automatic Oilers Upgrade	**2030**	$ 134,922									
Head Office Support	**Div_54 - Head Office Support**	Distribution Stations	**Fail**	Dollar threshold	**735243**	2031 Turbine Meter Automatic Oilers Upgrade	**2031**	$ 136,116									
Head Office Support	**Div_54 - Head Office Support**	Distribution Stations	**Fail**	Dollar threshold	**735244**	2032 Turbine Meter Automatic Oilers Upgrade	**2032**	$ 134,741									
Head Office Support	**Div_54 - Head Office Support**	Distribution Stations	**Fail**	Dollar threshold	**735245**	2027 Fire Suppression and Auto Transfer Generator	**2027**	$ 693,871									
Head Office Support	**Div_54 - Head Office Support**	Distribution Stations	**Fail**	Timing	**102668**	2024 Odourant Upgrades - MOIS Upgrades*	**2024**	$ 1,640,471				Within 3 years, supply side not applicable					
Head Office Support	**Div_54 - Head Office Support**	Distribution Stations	**Fail**	Timing	**102669**	2025 Odourant Upgrades - MOIS Upgrades*	**2025**	$ 1,692,575				Within 3 years, supply side not applicable					
Head Office Support	**Div_54 - Head Office Support**	Distribution Stations	**Fail**	Timing	**102726**	2023 RTU Upgrade Program*	**2023**	$ 1,619,189				Within 3 years, supply side not applicable					
Head Office Support	**Div_54 - Head Office Support**	Distribution Stations	**Fail**	Timing	**102727**	2024 RTU Upgrade Program*	**2024**	$ 1,537,942				Within 3 years, supply side not applicable					
Head Office Support	**Div_54 - Head Office Support**	Distribution Stations	**Fail**	Timing	**102728**	2025 RTU Upgrade Program*	**2025**	$ 1,571,211				Within 3 years, supply side not applicable					
Head Office Support	**Div_54 - Head Office Support**	Distribution Stations	**Fail**	Timing	**501373**	2023 Fire Suppression and Auto Transfer Generator	**2023**	$ 2,535,900				Within 3 years, supply side not applicable					
Head Office Support	**Div_54 - Head Office Support**	Distribution Stations	**Fail**	Timing	**501374**	2024 Fire Suppression and Auto Transfer Generator*	**2024**	$ 2,509,409				Within 3 years, supply side not applicable					
Head Office Support	**Div_54 - Head Office Support**	Distribution Stations	**Fail**	Timing	**501375**	2025 Fire Suppression and Auto Transfer Generator*	**2025**	$ 2,582,900				Within 3 years, supply side not applicable					
Head Office Support	**Div_54 - Head Office Support**	Distribution Stations	**Fail**	Emergent Safety	**48743**	Distribution Operations Station Maintenance Blankets*		$ 21,900,914									
Head Office Support	**Div_54 - Head Office Support**	Distribution Stations	**Pass**		**48667**	CNG Stations - Project #4	**2023**	$ 3,113,826	**Traditionally, fleet operators fuel their vehicles with gasoline or diesel. EGI promotes the use of natural gas to these customers as an alternate fuel source to provide a lower-cost and lower-emission fueling solution for vehicles such as garbage trucks, light duty vehicles, and transit buses. Business Development is responsible for the installation, maintenance, and the safe and continued operation of NGT stations assets for these customers. NGT stations differ in operation from distribution system stations as NGT stations use and store compressed natural gas (CNG) on site at up to 4000psi. EGD has two general categories for NGT station types: Large, Mobile and Utility NGT stations and Small NGT stations (also referred to as VRAs). Large, Mobile and Utility NGT stations are similar in operation and will be evaluated for condition in the same manner.**	Complete	**Fail**	See investment description, IRPAs not appliable for CNG					
Head Office Support	**Div_54 - Head Office Support**	Distribution Stations	**Pass**		**48744**	Distribution Operations Station Painting*		$ 26,848,160	**Issue/concern: This is a centrally managed program in the Union rate zone to apply high performance paint to stations where existing paint has begun to fail or wear off of the facilities on which it has been applied. The Station Painting Program is a significant corrosion mitigation practice. The frequency and criteria for high performance painting at station sites is specifically prescribed in the Corrosion Control Standard Operating Practice (SOP) and is its documented and committed practice on its compliance with the applicable codes for corrosion control on above-grade station assets. This work will improve compliance and ensure the safety and reliability of EGI assets by reducing the risk of leaks and piping and/or equipment failure due to significant corrosion. Assets: Related Programs (enter N/A if not applicable):**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office Support	**Div_54 - Head Office Support**	Distribution Stations	**Pass**		**501127**	FIMP Station Assessment Program*		$ 46,581,557	**Issue/Concern/Opportunity: FIMP assesses stations against threats that are listed in the EGI Hazard and Risk Common Register Risk Register to identify susceptibility to identified risks and determine mitigation strategies for individual sites, ensuring that risk is managed to the lowest practical levels. The strategy for the FIMP program is to perform inspections using with approved technologies used at EGI or other utilities for similar asset types. These inspections will assess the condition of existing station assets and will detect any concerns or issues to help determine the likelihood and consequence of failure of individual components and evaluate the risk. This strategy will allow for targeted replacement and will extend the useful life of assets by identifying condition issues prior to the occurrence of an incident. 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. Assets: FIMP DS Stations Related Investments: N/A**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office Support	**Div_54 - Head Office Support**	Distribution Stations	**Pass**		**501672**	2026 Fire Suppression and Auto Transfer Generator*	**2026**	$ 2,841,026	**Issue/Concern/Opportunity: 75 buildings that have Odourant inside need fire suppression and 59 need auto transfer generators - as of now 16 have auto transfer generators, this is due to code compliance with building code and the fire code. Justification: To install fire suppression systems inside 75 Odourant buildings in order to be compliant with the fire code and 59 auto transfer generators which need to be installed for the emergency lighting based on the building code, maintaining 30 minutes of light to meet code requirements. Additional compliance requirements to be accordance with the LEG Building Standard to install with methane and CO gas detectors in the boiler building as per page 26. The building standard is being integrated and the above requirement will still be considered requiring the boiler buildings to be equipped through this installation program. Buildings with Gas Burning assets require CO and CH4 Detectors, buildings with gas require CO detectors. This work is in accordance with Code Sections: Ontario Building Code Sections: 9.10.1.3, 3.2.2.71, 3.2.4.1, 3.2.9.1, 3.2.9.2 to 3.2.9.7, 3.3.1.5.(1) and 3.3.5.2 Ontario Fire Code Sections: 2.8, 4.1.5.6, 4.2.7.7**, 4.3.12, 4.3.13.1, 4.3.13.4, 6.2, 6.8.1.1** Assets: 75 LUG Stations Related Investments:**	Complete	**Fail**	See investment description, IRPAs not appliable					

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Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
Head Office Support	**Div_54 - Head Office Support**	Distribution Stations	**Pass**		**733885**	Operations Services Central IRR Program	**2022**	$ 23,657,218	**Issue/Concern/Opportunity: GDS has performed a survey to identify inside regulation at Customer Stations where the risk assessment identified the hazard of leaks from higher operating pressure piping will have a larger leak rate than pipes operating at lower pressures (for same hole size). Indoor regulators cause higher operating pressure pipe indoors - potential leaks may be able to reach LFL faster. Depending on leak rate, building ventilation, and room size, it is possible for indoor gas leak to build up to LFL leading to possible ignition resulting in an explosion. GDS is executing a program to relocate indoor regulators into an external regulator room (ERR) or relocate outdoors if possible. Some locations may not be immediately possible to relocate due to external factors not under the company's control, however over the long-term relocation may be possible. Similar treatment plans were previously considered and initiated in both legacy parts of the business. Review of Inside Regulator Rooms (IRR) in the LUG system and remediation as required Justification: We no longer allow IRRs as part of our standard designs as they pose various operational risks. Assets: Assets span the entire LUG system, review was done for all areas Related Investments:**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office Support	**Div_54 - Head Office Support**	Distribution Stations	**Pass**		**735115**	LUG DS - Gate, Feeder & A Stations Program*	**2031**	$ 146,545,887	**Issue/concern: This Investment was created to hold program dollars for future projects that are not yet identified and/or developed for years later in the capital plan. Assets: Related Programs (enter N/A if not applicable):**	Planned							
Head Office Support	**Div_54 - Head Office Support**	Distribution Stations	**Pass**		**735204**	2026 RTU Upgrade Program*	**2026**	$ 1,961,237	**Issue/Concern: The forecast in this category includes projects to replace all the existing remote terminal units and replace with current technology, the ControlWave Micro introduced in 2003. Many current Remote Telemetry Units (RTUs) are 3330/3310 which have been obsolete since 2009 and are no longer supported by the manufacturer. This is a standardized approach that ensures enhanced control and current communication protocols for SCADA Gas Control, odourization, measurement data collection and volume nominations. Starting in 2024, the SCADA RTU lifecycle project will take over as the current technology will be 21 years old. The benefit of these projects will be smooth migration of in-service RTU fleet to current technology using a standardized approach. Currently, these legacy RTUs are at end-of-life and deferring this work may increase failure rate drastically due to the “wear-out” effect. Asset: System Station Assets Related Program: N/A**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office Support	**Div_54 - Head Office Support**	Distribution Stations	**Pass**		**735205**	2027 RTU Upgrade Program*	**2027**	$ 2,192,853	**Issue/Concern: The forecast in this category includes projects to replace all the existing remote terminal units and replace with current technology, the ControlWave Micro introduced in 2003. Many current Remote Telemetry Units (RTUs) are 3330/3310 which have been obsolete since 2009 and are no longer supported by the manufacturer. This is a standardized approach that ensures enhanced control and current communication protocols for SCADA Gas Control, odourization, measurement data collection and volume nominations. Starting in 2024, the SCADA RTU lifecycle project will take over as the current technology will be 21 years old. The benefit of these projects will be smooth migration of in-service RTU fleet to current technology using a standardized approach. Currently, these legacy RTUs are at end-of-life and deferring this work may increase failure rate drastically due to the “wear-out” effect. Asset: System Station Assets Related Program: N/A**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office Support	**Div_54 - Head Office Support**	Distribution Stations	**Pass**		**735206**	2028 RTU Upgrade Program*	**2028**	$ 2,283,303	**Issue/Concern: The forecast in this category includes projects to replace all the existing remote terminal units and replace with current technology, the ControlWave Micro introduced in 2003. Many current Remote Telemetry Units (RTUs) are 3330/3310 which have been obsolete since 2009 and are no longer supported by the manufacturer. This is a standardized approach that ensures enhanced control and current communication protocols for SCADA Gas Control, odourization, measurement data collection and volume nominations. Starting in 2024, the SCADA RTU lifecycle project will take over as the current technology will be 21 years old. The benefit of these projects will be smooth migration of in-service RTU fleet to current technology using a standardized approach. Currently, these legacy RTUs are at end-of-life and deferring this work may increase failure rate drastically due to the “wear-out” effect. Asset: System Station Assets Related Program: N/A**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office Support	**Div_54 - Head Office Support**	Distribution Stations	**Pass**		**735207**	2029 RTU Upgrade Program*	**2029**	$ 2,380,301	**Issue/Concern: The forecast in this category includes projects to replace all the existing remote terminal units and replace with current technology, the ControlWave Micro introduced in 2003. Many current Remote Telemetry Units (RTUs) are 3330/3310 which have been obsolete since 2009 and are no longer supported by the manufacturer. This is a standardized approach that ensures enhanced control and current communication protocols for SCADA Gas Control, odourization, measurement data collection and volume nominations. Starting in 2024, the SCADA RTU lifecycle project will take over as the current technology will be 21 years old. The benefit of these projects will be smooth migration of in-service RTU fleet to current technology using a standardized approach. Currently, these legacy RTUs are at end-of-life and deferring this work may increase failure rate drastically due to the “wear-out” effect. Asset: System Station Assets Related Program: N/A**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office Support	**Div_54 - Head Office Support**	Distribution Stations	**Pass**		**735208**	2030 RTU Upgrade Program*	**2030**	$ 2,587,903	**Issue/Concern: The forecast in this category includes projects to replace all the existing remote terminal units and replace with current technology, the ControlWave Micro introduced in 2003. Many current Remote Telemetry Units (RTUs) are 3330/3310 which have been obsolete since 2009 and are no longer supported by the manufacturer. This is a standardized approach that ensures enhanced control and current communication protocols for SCADA Gas Control, odourization, measurement data collection and volume nominations. Starting in 2024, the SCADA RTU lifecycle project will take over as the current technology will be 21 years old. The benefit of these projects will be smooth migration of in-service RTU fleet to current technology using a standardized approach. Currently, these legacy RTUs are at end-of-life and deferring this work may increase failure rate drastically due to the “wear-out” effect. Asset: System Station Assets Related Program: N/A**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office Support	**Div_54 - Head Office Support**	Distribution Stations	**Pass**		**735209**	2031 RTU Upgrade Program*	**2031**	$ 2,687,583	**Issue/Concern: The forecast in this category includes projects to replace all the existing remote terminal units and replace with current technology, the ControlWave Micro introduced in 2003. Many current Remote Telemetry Units (RTUs) are 3330/3310 which have been obsolete since 2009 and are no longer supported by the manufacturer. This is a standardized approach that ensures enhanced control and current communication protocols for SCADA Gas Control, odourization, measurement data collection and volume nominations. Starting in 2024, the SCADA RTU lifecycle project will take over as the current technology will be 21 years old. The benefit of these projects will be smooth migration of in-service RTU fleet to current technology using a standardized approach. Currently, these legacy RTUs are at end-of-life and deferring this work may increase failure rate drastically due to the “wear-out” effect. Asset: System Station Assets Related Program: N/A**	Complete	**Fail**	See investment description, IRPAs not appliable					

* in the Investment Name indicates a program item. Program items are unique as they represent numerous projects grouped together and budgeted in advance. This results in forecast spend appearing larger than it would at the project level and it also impacts the in-service dates

Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
Head Office Support	**Div_54 - Head Office Support**	Distribution Stations	**Pass**		**735210**	2032 RTU Upgrade Program*	**2032**	$ 2,738,698	**Issue/Concern: The forecast in this category includes projects to replace all the existing remote terminal units and replace with current technology, the ControlWave Micro introduced in 2003. Many current Remote Telemetry Units (RTUs) are 3330/3310 which have been obsolete since 2009 and are no longer supported by the manufacturer. This is a standardized approach that ensures enhanced control and current communication protocols for SCADA Gas Control, odourization, measurement data collection and volume nominations. Starting in 2024, the SCADA RTU lifecycle project will take over as the current technology will be 21 years old. The benefit of these projects will be smooth migration of in-service RTU fleet to current technology using a standardized approach. Currently, these legacy RTUs are at end-of-life and deferring this work may increase failure rate drastically due to the "wear-out" effect. Asset: System Station Assets Related Program: N/A**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office Support	**Div_54 - Head Office Support**	Distribution Stations	**Pass**		**735211**	2026 Odourant Upgrades - MOIS Upgrades*	**2026**	$ 2,033,809	**The expenditures in this portfolio include projects 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. This forecast will help mitigate the risk of tank rupture, frequent freeze off and nuisance odour calls.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office Support	**Div_54 - Head Office Support**	Distribution Stations	**Pass**		**735213**	2027 Odourant Upgrades - MOIS Upgrades*	**2027**	$ 2,165,712	**The expenditures in this portfolio include projects 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. This forecast will help mitigate the risk of tank rupture, frequent freeze off and nuisance odour calls.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office Support	**Div_54 - Head Office Support**	Distribution Stations	**Pass**		**735214**	2028 Odourant Upgrades - MOIS Upgrades*	**2028**	$ 2,147,659	**The expenditures in this portfolio include projects 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. This forecast will help mitigate the risk of tank rupture, frequent freeze off and nuisance odour calls.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office Support	**Div_54 - Head Office Support**	Distribution Stations	**Pass**		**735215**	2029 Odourant Upgrades - MOIS Upgrades*	**2029**	$ 2,132,281	**The expenditures in this portfolio include projects 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. This forecast will help mitigate the risk of tank rupture, frequent freeze off and nuisance odour calls.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office Support	**Div_54 - Head Office Support**	Distribution Stations	**Pass**		**735216**	2030 Odourant Upgrades - MOIS Upgrades*	**2030**	$ 2,207,858	**The expenditures in this portfolio include projects 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. This forecast will help mitigate the risk of tank rupture, frequent freeze off and nuisance odour calls.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office Support	**Div_54 - Head Office Support**	Distribution Stations	**Pass**		**735217**	2031 Odourant Upgrades - MOIS Upgrades*	**2031**	$ 2,183,714	**The expenditures in this portfolio include projects 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. This forecast will help mitigate the risk of tank rupture, frequent freeze off and nuisance odour calls.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office Support	**Div_54 - Head Office Support**	Distribution Stations	**Pass**		**735218**	2032 Odourant Upgrades - MOIS Upgrades*	**2032**	$ 2,119,281	**The expenditures in this portfolio include projects 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. This forecast will help mitigate the risk of tank rupture, frequent freeze off and nuisance odour calls.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office Support	**Div_54 - Head Office Support**	Growth	**Pass**		**49179**	SRP_Southeast_Port Rowan_Lakeshore Rd_Reinforcement_NPS6_2000m_860kPa	**2024**	$ 1,473,861	**System Reinforcement - Replace existing 3-inch 860 Maximum Operating Pressure (MOP) line with 6-inch in Phase 1. Move forward from 2026 to 2024 per 2021 System Reinforcement Plan (SRP) refresh.**	Planned							
Head Office Support	**Div_54 - Head Office Support**	Utilization	**Fail**	Dollar threshold	**102816**	2023 - LAB FACILITIES UPGRADE	**2023**	$ 99,642									
Head Office Support	**Div_54 - Head Office Support**	Utilization	**Fail**	Dollar threshold	**102817**	2024 - LAB FACILITIES UPGRADE	**2024**	$ 102,529									
Head Office Support	**Div_54 - Head Office Support**	Utilization	**Fail**	Dollar threshold	**102818**	2025 - LAB FACILITIES UPGRADE	**2025**	$ 103,316									
Head Office Support	**Div_54 - Head Office Support**	Utilization	**Fail**	Dollar threshold	**736034**	Commercial / Industrial LPDMS*	**2021**	$ 1,160,367									
Head Office Support	**Div_54 - Head Office Support**	Utilization	**Pass**		**48500**	SMC-Meter & Regulator Additions South*		$ 41,354,891	**Meter & Reg Install- New**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office Support	**Div_54 - Head Office Support**	Utilization	**Pass**		**48501**	SMC_Meter & Regulator Replacements - South*	**2020**	$ 183,636,762	**Meter & Reg Install- Replacement**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office Support	**Div_54 - Head Office Support**	Utilization	**Pass**		**48679**	SMC-Meter & Regulator Additions North*		$ 11,327,082	**Meter & Reg Install- New**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office Support	**Div_54 - Head Office Support**	Utilization	**Pass**		**48680**	SMC_Meter & Regulator Replacements - North*	**2020**	$ 48,473,262	**Meter & Reg Install- Replacement**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office Support	**Div_54 - Head Office Support**	Utilization	**Pass**		**502199**	Farm Tap Program (LUG)*	**2021**	$ 3,093,332	**The Farm Tap regulator purpose is to reduce pressure from XHP/HP to meet the design criteria for the downstream 2nd cut 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 the customer's premise. This over-pressure can result in downstream customer appliances failing, loss of containment inside the premise, fire, and explosion. The Farm Tap consists of the inlet/outlet riser, a regulator, and a relief. The condition of the Farm Tap population is largely unknown. As they are installed away from the premise and near the property line, they 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. Farm Taps have not been part of pro-active inspection programs. They historically have not been included in MXGI regulator exchanges. 2021 DIMP survey for LUG - potential for some immediates**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office Support	**Div_54 - Head Office Support**	Utilization	**Pass**		**738584**	SMC_Meter & Regulator Replacements - North*		$ 14,218,452	**Meter & Reg Install- Replacement**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office Support	**Div_54 - Head Office Support**	Utilization	**Pass**		**738583**	SMC_Meter & Regulator Replacements - South*		$ 53,923,496	**Meter & Reg Install- Replacement**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office Support	**Div_54 - Head Office Support**	Transmission Pipe & Underground Storage	**Fail**	Timing	**102546**	Class Location Replacement Program 2023 - S&T Assets*	**2023**	$ 1,245,530				Within 3 years, supply side not applicable					
Head Office Support	**Div_54 - Head Office Support**	Transmission Pipe & Underground Storage	**Fail**	Timing	**102552**	Class Location Replacement Program 2024 - S&T Assets*	**2024**	$ 2,643,338				Within 3 years, supply side not applicable					
Head Office Support	**Div_54 - Head Office Support**	Transmission Pipe & Underground Storage	**Fail**	Timing	**102553**	Class Location Replacement Program 2025 - S&T Assets*	**2025**	$ 4,035,782				Within 3 years, supply side not applicable					

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Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
Head Office Support	**Div_54 - Head Office Support**	Transmission Pipe & Underground Storage	**Pass**		**102554**	Class Location Replacement Program 2026 - S&T Assets*	**2034**	$ 5,457,245	**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, 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 in order to meet the 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.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office Support	**Div_54 - Head Office Support**	Transmission Pipe & Underground Storage	**Pass**		**102555**	Class Location Replacement Program 2027 - S&T Assets*	**2035**	$ 7,285,651	**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, 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 in order to meet the 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.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office Support	**Div_54 - Head Office Support**	Transmission Pipe & Underground Storage	**Pass**		**102556**	Class Location Replacement Program 2028 - S&T Assets*	**2036**	$ 7,224,918	**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, 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 in order to meet the 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.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office Support	**Div_54 - Head Office Support**	Transmission Pipe & Underground Storage	**Pass**		**102557**	Class Location Replacement Program 2029 - S&T Assets*	**2037**	$ 7,173,186	**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, 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 in order to meet the 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.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office Support	**Div_54 - Head Office Support**	Transmission Pipe & Underground Storage	**Pass**		**102558**	Class Location Replacement Program 2030 - S&T Assets*	**2038**	$ 7,427,434	**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, 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 in order to meet the 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.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office Support	**Div_54 - Head Office Support**	Transmission Pipe & Underground Storage	**Pass**		**733985**	Class Location Replacement Program 2031 - S&T Assets*	**2039**	$ 7,346,212	**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, 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 in order to meet the 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.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office Support	**Div_54 - Head Office Support**	Transmission Pipe & Underground Storage	**Pass**		**733986**	Class Location Replacement Program 2032 - S&T Assets*	**2040**	$ 7,129,454	**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, 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 in order to meet the 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.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office/All	**00 - Head Office**	Distribution Pipe	**Pass**		**736833**	TIMP Geohazard Mitigation (LUG)*		$ 24,533,407	**General: The Geohazard Mitigation program has been designed to comply with all applicable codes and standards. The program consists of the assessment and maintenance of the integrity of EGI's pipeline systems which may be impacted by geohazards. The assessment ensures asset's continued safety and reliability. Most of the expenditure included in this category is for pipelines that operate above 30 per cent SMYS.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office/All	**00 - Head Office**	Distribution Pipe	**Pass**		**736835**	TIMP Geohazard Mitigation (LEGD)*		$ 6,133,885	**General: The Geohazard Mitigation Program has been designed to comply with all applicable codes and standards. The program consists of the assessment and maintenance of the integrity of EGI's pipeline systems which may be impacted by geohazards. The assessment ensures asset's continued safety and reliability. Most of the expenditure included in this category is for pipelines that operate above 30% SMYS.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office/All	**00 - Head Office**	Distribution Pipe	**Pass**		**736844**	Independent Asset Integrity Review (IAIR) - (LUG)*		$ 81,727,582	**Dynamic Risk completed an independent review of TIMP to establish uncertainty levels in the fitness-for-service conclusions for all TIMP assets. This first phase of the project was completed last year. TIMP is currently developing plans to mitigate high and moderate uncertainties in the fitness-for-service conclusions by leveraging existing integrity activities and potentially introducing new ones.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office/All	**00 - Head Office**	Distribution Pipe	**Pass**		**736845**	Independent Asset Integrity Review (IAIR) - (LEG)*		$ 8,863,546	**Dynamic Risk completed an independent review of TIMP to establish uncertainty levels in the fitness-for-service conclusions for all TIMP assets. This first phase of the project was completed last year. TIMP is currently developing plans to mitigate high and moderate uncertainties in the fitness-for-service conclusions by leveraging existing integrity activities and potentially introducing new ones.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office/All	**00 - Head Office**	Distribution Stations	**Fail**	Dollar threshold	**17404**	NGV Rental VRA's - (2026-2032)	**2028**	$ 1,346,723									
Head Office/All	**00 - Head Office**	Distribution Stations	**Pass**		**2368**	NGV Rental VRA's	**2025**	$ 491,108	**Issue/concern: Individual customers and arenas can achieve fuel cost savings, fuel handling savings, and reduced emission benefits by operating their cleaning machines, forklift trucks, and individual light-duty vehicles on natural gas versus propane or gasoline. This presents an opportunity to grow EGI's natural gas vehicle (NGV) rental refueling business and promotes the use of natural gas to customers as an alternate source for fueling cleaning machines, forklift trucks, and individual light-duty vehicles at a lower cost, reducing fuel handling cost with lower emissions. By providing NGV Vehicle Refueling Appliance (VRA) equipment to customers on a rental basis, EGI can achieve growth in the marketplace, while fully recovering costs.** **Assets: There are currently over 200 VRA customers that EGI is successfully servicing, including City of Toronto, City of Ottawa, other small city arenas and some private customers.** **Related Program (if applicable): Not applicable.**	Planned							
Head Office/All	**00 - Head Office**	Distribution Stations	**Pass**		**503415**	Bellville Yard Station	**2024**	$ 1,922,427	**The Enbridge fleet continues to achieve fuel cost savings and reduced emission benefits by operating their light-duty vehicles on natural gas versus gasoline.**	Planned							
Head Office/All	**00 - Head Office**	Transmission Pipe & Underground Storage	**Pass**		**736880**	Independent Asset Integrity Review (IAIR) - EGDTP*		$ 13,295,319	**Dynamic Risk completed an independent review of TIMP to establish uncertainty levels in the fitness-for-service conclusions for all TIMP assets. This first phase of the project was completed last year. TIMP is currently developing plans to mitigate high and moderate uncertainties in the fitness-for-service conclusions by leveraging existing integrity activities and potentially introducing new ones.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office/All	**00 - Head Office**	Transmission Pipe & Underground Storage	**Pass**		**736881**	Independent Asset Integrity Review (IAIR) - UGTP*		$ 19,170,667	**Dynamic Risk completed an independent review of TIMP to establish uncertainty levels in the fitness-for-service conclusions for all TIMP assets. This first phase of the project was completed last year. TIMP is currently developing plans to mitigate high and moderate uncertainties in the fitness-for-service conclusions by leveraging existing integrity activities and potentially introducing new ones.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office/All	**01 - All**	Distribution Pipe	**Fail**	Dollar threshold	**102428**	Relocation Program - Transit*	**2020**	$ (46,507,007)									
Head Office/All	**01 - All**	Distribution Pipe	**Fail**	Dollar threshold	**102760**	2025 Integrity Dig Program*		$ 775,041									
Head Office/All	**01 - All**	Distribution Pipe	**Fail**	Timing	**102759**	2024 Integrity Dig Program*	**2024**	$ 6,406,884				Within 3 years, supply side not applicable					

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Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
Head Office/All	01 - All	Distribution Pipe	Fail	Timing	736439	General Mains Replacement Blanket - All Regions*	2020	$ 47,983,533				Within 3 years, supply side not applicable					
Head Office/All	01 - All	Distribution Pipe	Pass		6124	Depth of Cover Mitigation Program*		$ 6,088,895	Mitigation of depth of cover sites on >30% SMYS lines that are out of compliance with CSA Z662 & TSSA requirements. Some of the known sites are discovered during the annual Depth of Cover Survey, while others are reported by company crews when performing maintenance work or by 3rd party . At this time the specific work scope of each year is not defined and this is a blanket program as a placeholder in the budget. The mitigation work will include the construction costs from sites identified and planned for the current year, as well as work on sites that are newly identified. Scope of work can vary from small remediation projects to add fill, concrete or bank stabilization, to short replacement of pipe.	Complete	Fail	See investment description, IRPAs not appliable					
Head Office/All	01 - All	Distribution Pipe	Pass		100225	Rectifier Program - All Areas*		$ 3,674,496	Issue/Concern: This business case is created to group all Anode Blanket projects for all seven operations areas into one program business case to simplify the Risk Assessment process. Financial tracking will be done on the individual Blanket Anode project to provide financial reporting per area. Justification: The Corrosion Department conducts pipe to soil readings each year on our steel pipelines. When they identify a corrosion area which has fallen below our minimum specifications, they process an order for a anode installation which is completed. The capital request is for 12 months. Engineering has confirmed the Anode Installation as a compliance project. The Corrosion Prevention Program consists of the annual anode replacement to ensure the steel main system is receiving sufficient cathodic protection. The Program utilizes pipe-to-soil survey results to determine which steel main networks require additional or replacement anodes to improve the level of cathodic protection. In addition to active steel mains, the Corrosion Prevention Programs also cover the corrosion control on steel casings. Assets: Steel Mains Related Programs/Business Cases: N/A	Complete	Fail	See investment description, IRPAs not appliable					
Head Office/All	01 - All	Distribution Pipe	Pass		100444	Integrity Retrofit Program >30% SMYS*		$ 21,792,827	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 inline 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 that are identified through the inspections.	Complete	Fail	See investment description, IRPAs not appliable					
Head Office/All	01 - All	Distribution Pipe	Pass		102758	2023 Integrity Dig Program*		$ 1,995,058	2023 forecast: 8 ILI digs estimated based on previous years inspection plan. 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 inline 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 that are identified through the inspections.	Complete	Fail	See investment description, IRPAs not appliable					
Head Office/All	01 - All	Distribution Pipe	Pass		102761	2026 Integrity Dig Program*		$ 3,661,501	Forecast: Forecast not provided for 2026-3030; average of 2020-2025 used as a placeholder. 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 inline 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 that are identified through the inspections.	Complete	Fail	See investment description, IRPAs not appliable					
Head Office/All	01 - All	Distribution Pipe	Pass		102762	2027 Integrity Dig Program*		$ 3,890,911	Forecast: Forecast not provided for 2026-3030; average of 2020-2025 used as a placeholder. 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 inline 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 that are identified through the inspections.	Complete	Fail	See investment description, IRPAs not appliable					
Head Office/All	01 - All	Distribution Pipe	Pass		102763	2028 Integrity Dig Program*		$ 3,857,753	Forecast: Forecast not provided for 2026-3030; average of 2020-2025 used as a placeholder. 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 inline 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 that are identified through the inspections.	Complete	Fail	See investment description, IRPAs not appliable					
Head Office/All	01 - All	Distribution Pipe	Pass		102764	2029 Integrity Dig Program*		$ 3,835,204	Forecast: Forecast not provided for 2026-2030; average of 2020-2025 used as a placeholder. 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 inline 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 that are identified through the inspections.	Complete	Fail	See investment description, IRPAs not appliable					
Head Office/All	01 - All	Distribution Pipe	Pass		102765	2030 Integrity Dig Program*		$ 3,950,198	Forecast: Forecast not provided for 2026- 2030; average of 2020-2025 used as a placeholder. 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 inline 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 that are identified through the inspections.	Complete	Fail	See investment description, IRPAs not appliable					
Head Office/All	01 - All	Distribution Pipe	Pass		502013	Relocation Program - Engineering Construction*	2020	$ 22,737,340	General: Projects in the relocation category are capital expenditures required to replace or relocate segments of pipeline in order to accommodate municipal infrastructure work. The cost sharing for this work is managed through the Franchise Agreements established with municipalities. A consultative approach is used between the municipality and EGI to avoid conflicts with municipal infrastructure early in the planning stage. If a conflict is unavoidable, pipeline assets are typically relocated or replaced.	Planned							
Head Office/All	01 - All	Distribution Pipe	Pass		503432	Bridge Crossing Painting Program*		$ 2,687,789	Issue/Concern/Opportunity: Bridge crossing inspection results in different levels of action which can include replacement, recoating, or hanger repair/replacement work. This program is for recoating work and hanger repair. Justification: The integrated Corrosion Operating Standard ST-17-B13A-DDA9 was released November 25, 2022 and requires the following surveys: Annual visual and 5-year detailed. The standard outlines the following time frames: •Bridge crossing – replace per Engineering assessment per project plan •Bridge crossing – replace expansion joint / Ins flange within 24 month •Bridge crossing – paint pipe / repair hangers / replace casing end seal within 12 months.	Complete	Fail	See investment description, IRPAs not appliable					
Head Office/All	01 - All	Distribution Pipe	Pass		733993	2031 Integrity Dig Program*		$ 3,905,461	Forecast: Forecast not provided for 2026- 2030; average of 2020-2025 used as a placeholder. 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 inline 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 that are identified through the inspections.	Complete	Fail	See investment description, IRPAs not appliable					

* in the Investment Name indicates a program item. Program items are unique as they represent numerous projects grouped together and budgeted in advance. This results in forecast spend appearing larger than it would at the project level and it also impacts the in-service dates

Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
Head Office/All	01 - All	Distribution Pipe	Pass		733994	2032 Integrity Dig Program*		$ 3,792,072	Forecast: Forecast not provided for 2026- 2030; average of 2020-2025 used as a placeholder. 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 inline 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 that are identified through the inspections.	Complete	Fail	See investment description, IRPAs not appliable					
Head Office/All	01 - All	Distribution Stations	Fail	Dollar threshold	9842	2023 Header stations rebuilds*	2023	$ 1,152,146									
Head Office/All	01 - All	Distribution Stations	Fail	Dollar threshold	9843	2024 Header stations rebuilds*	2024	$ 1,183,992									
Head Office/All	01 - All	Distribution Stations	Fail	Dollar threshold	9844	2023 Sales stations rebuilds*	2023	$ 1,246,911									
Head Office/All	01 - All	Distribution Stations	Fail	Dollar threshold	10300	2025 Header stations rebuilds*	2025	$ 1,193,563									
Head Office/All	01 - All	Distribution Stations	Fail	Dollar threshold	10301	2026 Header stations rebuilds*	2026	$ 1,208,295									
Head Office/All	01 - All	Distribution Stations	Fail	Dollar threshold	10303	2024 Sales stations rebuilds*	2024	$ 1,281,377									
Head Office/All	01 - All	Distribution Stations	Fail	Dollar threshold	10304	2025 Sales stations rebuilds*	2025	$ 1,291,735									
Head Office/All	01 - All	Distribution Stations	Fail	Dollar threshold	10361	2026 Sales stations rebuilds*	2026	$ 1,307,679									
Head Office/All	01 - All	Distribution Stations	Fail	Dollar threshold	10362	2027 Sales stations rebuilds*	2027	$ 1,389,611									
Head Office/All	01 - All	Distribution Stations	Fail	Dollar threshold	10541	2027 Header stations rebuilds*	2027	$ 1,284,001									
Head Office/All	01 - All	Distribution Stations	Fail	Dollar threshold	16432	2028 Header stations rebuilds*	2028	$ 1,273,059									
Head Office/All	01 - All	Distribution Stations	Fail	Dollar threshold	16433	2028 Sales stations rebuilds*	2028	$ 1,377,769									
Head Office/All	01 - All	Distribution Stations	Fail	Dollar threshold	101554	2029 Header stations rebuild*	2029	$ 1,265,617									
Head Office/All	01 - All	Distribution Stations	Fail	Dollar threshold	101555	2030 Header stations rebuilds*	2030	$ 1,303,565									
Head Office/All	01 - All	Distribution Stations	Fail	Dollar threshold	101558	2029 Sales stations rebuilds*	2029	$ 1,369,716									
Head Office/All	01 - All	Distribution Stations	Fail	Dollar threshold	101559	2030 Sales stations rebuilds*	2030	$ 1,410,785									
Head Office/All	01 - All	Distribution Stations	Fail	Dollar threshold	734297	2031 Sales stations rebuilds*	2031	$ 1,394,807									
Head Office/All	01 - All	Distribution Stations	Fail	Dollar threshold	734298	2032 Sales stations rebuilds*	2032	$ 1,354,311									
Head Office/All	01 - All	Distribution Stations	Fail	Dollar threshold	734299	2031 Header stations rebuilds*	2031	$ 1,288,802									
Head Office/All	01 - All	Distribution Stations	Fail	Dollar threshold	734300	2032 Header stations rebuilds*	2032	$ 1,251,384									
Head Office/All	01 - All	Distribution Stations	Fail	Timing	9845	2024 Telemetry*	2024	$ 1,573,531				Within 3 years, supply side not applicable					
Head Office/All	01 - All	Distribution Stations	Fail	Timing	9846	2023 Telemetry*	2023	$ 1,745,676				Within 3 years, supply side not applicable					
Head Office/All	01 - All	Distribution Stations	Fail	Timing	9964	2025 Telemetry*	2025	$ 1,623,142				Within 3 years, supply side not applicable					
Head Office/All	01 - All	Distribution Stations	Fail	Timing	10296	2024 District Station Rebuilds Program*	2024	$ 4,988,398				Within 3 years, supply side not applicable					
Head Office/All	01 - All	Distribution Stations	Fail	Timing	10297	2025 District Station Rebuilds Program*	2025	$ 6,306,185				Within 3 years, supply side not applicable					
Head Office/All	01 - All	Distribution Stations	Pass		9552	NGT Existing customer Maintenance Capital - (Until 2026)*		$ 1,585,984	Maintenance capital for refueling stations for external customer stations only Issue/concern: EGI fleet operators can continue to achieve fuel cost savings and reduced emission benefits by investing in the wellbeing of the NGV station. This can be achieved by adopting and continuously upgrading their NGV equipment as part of the maintenance strategy. By upgrading major NGV equipment, EGI can extend the life cycle of the equipment, resulting in a more cost-effective way of operating the NGV stations. Assets: There are a number of current NGV stations EGI maintains	Complete	Fail	See investment description, IRPAs not appliable for CNG					
Head Office/All	01 - All	Distribution Stations	Pass		9553	NGT Maintenance Capital for company/fleet NG refueling stations (2021 to 2032)*		$ 4,284,492	Maintenance capital for refueling stations for EGD NGT Fueling stations only Issue/concern: The EGD Fleet department can achieve fuel cost savings and reduced emission benefits by operating the 800-plus fleet vehicles on natural gas versus diesel or gasoline. This presents an opportunity for the EGD Fleet Department to realize fuel savings and promotes the use of natural gas to other fleet operators as an alternate source for fueling vehicles at a lower cost with lower emissions. By demonstrating the use of natural gas, EGD can achieve growth in the marketplace, while realizing fuel savings. Assets: EGD currently operates 19 Natural Gas Vehicle (NGV) fueling stations on company yards. The stations includes; Arnprior Yard, Barrie Yard, Beamsville Yard, Thorold Office, Brampton, Brockvill yard, Ottawa Office, Kelfield yard, Kennedy Road Yard, Midland Gate Station, Oshawa Office, Port Colbourne Yard, Peterborough yard, Shelburne Gate Station, South Merivall, Station B, Stayner Gate Station, Enbridge Training Centre, and the VPC Office. In addition, EGD will installing two new NGT stations to fuel recently converted vehicles and dedicated light duty trucks. These two new stations (Tecumseh Storage facility and Tallman Truck Center (Kemptville)) will also, need to be maintained. Related Program: N/A	Complete	Fail	See investment description, IRPAs not appliable for CNG					
Head Office/All	01 - All	Distribution Stations	Pass		9965	2026 Telemetry*	2026	$ 1,942,807	Telemetry systems are required to monitor and control our pipeline system. Applicable Codes: Z662, Sec 11.26.4 provides code requirement for safe and reliable communication. The Telemetry system includes communication paths from the instrumentation at our stations to Gas Control and it allows them to monitor EGI Distribution conditions. Gas flow: For gas supply to meet nominations Leak detection: Indicated by large pressure drops Overpressure protection and Pressure Control: Condition monitoring equipment by gas control ensures gas delivery to the customers in a controlled and safe manner. Included in this program are upgrades to the Telemetry network that include: 1)Cyber Security - Ongoing upgrades to Scada system to ensure compliance with EI Cyber security standards and proposed CSA code 2)Legacy equipment - 3330 Bristol units(10/yr) must be replaced with Control Wave Micro units 3) RTU Programming Manual - Development of manual detailing programming standards for design, security and expansion 4)SCADA - Development of maintenance layer of Scada to allow site reporting of gas consumption for boiler gas, odourant pump strokes and usage tracking, boiler diagnostics, remote engineering and automation of gate/feeder stations 5)Broadband Communication - Development of broadband links between major stations to support security (i.e. intrusion detection)	Complete	Fail	See investment description, IRPAs not appliable					

* in the Investment Name indicates a program item. Program items are unique as they represent numerous projects grouped together and budgeted in advance. This results in forecast spend appearing larger than it would at the project level and it also impacts the in-service dates

Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
Head Office/All	**01 - All**	Distribution Stations	**Pass**		**9966**	2027 Telemetry*	**2027**	$ 2,105,824	**Telemetry systems are required to monitor and control our pipeline system. Applicable Codes: Z662, Sec 11.26.4 provides code requirement for safe and reliable communication. The Telemetry system includes communication paths from the instrumentation at our stations to Gas Control and it allows them to monitor EGI Distribution conditions. Gas flow: For gas supply to meet nominations Leak detection: Indicated by large pressure drops Overpressure protection and Pressure Control: Condition monitoring equipment by gas control ensures gas delivery to the customers in a controlled and safe manner. Included in this program are upgrades to the Telemetry network that include: 1)Cyber Security - Ongoing upgrades to Scada system to ensure compliance with EI Cyber security standards and proposed CSA code 2)Legacy equipment - 3330 Bristol units(10/yr) must be replaced with Control Wave Micro units 3) RTU Programming Manual - Development of manual detailing programming standards for design, security and expansion 4)SCADA - Development of maintenance layer of Scada to allow site reporting of gas consumption for boiler gas, odourant pump strokes and usage tracking, boiler diagnostics, remote engineering and automation of gate/feeder stations 5)Broadband Communication - Development of broadband links between major stations to support security (i.e. intrusion detection)**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office/All	**01 - All**	Distribution Stations	**Pass**		**10298**	2026 District Station Rebuilds Program*	**2026**	$ 7,942,642	**Issue/Concern: The stations identified in this business case fall into one of the following categories: Below-ground box replacements: Removal of below-ground stations improves life cycle cost of stations due to accelerated corrosion related to salting and flooding, increased O&M costs related to increased paint frequency, and the requirement for two at a box when work is performed. An additional and very important benefit to the elimination of below-ground boxes is the improvement of worker health and safety by eliminating the need to handle potentially contaminated water, and non-ergonomic work conditions. Obsolete Regulators: The criteria for this category is that there are no spare parts available, or parts are no longer approved for use on new installations, or a combination of poor performance and manufacturer availability. Low Pressure Districts: The failure of a low pressure district can have disastrous downstream impacts in the event of over-pressure protection failure. The outlets of these stations feed customers who may not have individual regulators at their meter sets. This additional line of defense is not present to protect customer piping. Double Boot-style Regulators: Stations with both operator and monitor boot-style regulators have a common failure mechanism as a result of debris in the gas stream. Replacement of one boot-style regulator with a non-boot regulator reduces the vulnerability of failure. Increased Capacity: Stations that are operating over designed capacity due to system growth are targeted for replacement to maintain gas supply. Loss of Containment: Station experiencing loss of containment (leaks) and high maintenance calls to repair equipment are also identified for replacement. Asset: District station assets. Related Program: N/A**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office/All	**01 - All**	Distribution Stations	**Pass**		**10299**	2027 District Station Rebuilds Program*	**2027**	$ 8,189,676	**Issue/Concern: The stations identified in this business case fall into one of the following categories: Below-ground box replacements: Removal of below-ground stations improves life cycle cost of stations due to accelerated corrosion related to salting and flooding, increased O&M costs related to increased paint frequency, and the requirement for two at a box when work is performed. An additional and very important benefit to the elimination of below-ground boxes is the improvement of worker health and safety by eliminating the need to handle potentially contaminated water, and non-ergonomic work conditions. Obsolete Regulators: The criteria for this category is that there are no spare parts available, or parts are no longer approved for use on new installations, or a combination of poor performance and manufacturer availability. Low Pressure Districts: The failure of a low pressure district can have disastrous downstream impacts in the event of over-pressure protection failure. The outlets of these stations feed customers who may not have individual regulators at their meter sets. This additional line of defense is not present to protect customer piping. Double Boot-style Regulators: Stations with both operator and monitor boot-style regulators have a common failure mechanism as a result of debris in the gas stream. Replacement of one boot-style regulator with a non-boot regulator reduces the vulnerability of failure. Increased Capacity: Stations that are operating over designed capacity due to system growth are targeted for replacement to maintain gas supply. Loss of Containment: Station experiencing loss of containment (leaks) and high maintenance calls to repair equipment are also identified for replacement. Asset: District station assets. Related Program: N/A**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office/All	**01 - All**	Distribution Stations	**Pass**		**16430**	2028 Telemetry*	**2028**	$ 2,129,636	**Telemetry systems are required to monitor and control our pipeline system. Applicable Codes: Z662, Sec 11.26.4 provides code requirement for safe and reliable communication. The Telemetry system includes communication paths from the instrumentation at our stations to Gas Control and it allows them to monitor EGI Distribution conditions. Gas flow: For gas supply to meet nominations Leak detection: Indicated by large pressure drops Overpressure protection and Pressure Control: Condition monitoring equipment by gas control ensures gas delivery to the customers in a controlled and safe manner. Included in this program are upgrades to the Telemetry network that include: 1)Cyber Security - Ongoing upgrades to Scada system to ensure compliance with EI Cyber security standards and proposed CSA code 2)Legacy equipment - 3330 Bristol units(10/yr) must be replaced with Control Wave Micro units 3) RTU Programming Manual - Development of manual detailing programming standards for design, security and expansion 4)SCADA - Development of maintenance layer of Scada to allow site reporting of gas consumption for boiler gas, odourant pump strokes and usage tracking, boiler diagnostics, remote engineering and automation of gate/feeder stations 5)Broadband Communication - Development of broadband links between major stations to support security (i.e. intrusion detection)**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office/All	**01 - All**	Distribution Stations	**Pass**		**16434**	2028 District Station Rebuilds Program*	**2028**	$ 4,372,570	**Issue/Concern: The stations identified in this business case fall into one of the following categories: Below-ground box replacements: Removal of below-ground stations improves life cycle cost of stations due to accelerated corrosion related to salting and flooding, increased O&M costs related to increased paint frequency, and the requirement for two at a box when work is performed. An additional and very important benefit to the elimination of below-ground boxes is the improvement of worker health and safety by eliminating the need to handle potentially contaminated water, and non-ergonomic work conditions. Obsolete Regulators: The criteria for this category is that there are no spare parts available, or parts are no longer approved for use on new installations, or a combination of poor performance and manufacturer availability. Low Pressure Districts: The failure of a low pressure district can have disastrous downstream impacts in the event of over-pressure protection failure. The outlets of these stations feed customers who may not have individual regulators at their meter sets. This additional line of defense is not present to protect customer piping. Double Boot-style Regulators: Stations with both operator and monitor boot-style regulators have a common failure mechanism as a result of debris in the gas stream. Replacement of one boot-style regulator with a non-boot regulator reduces the vulnerability of failure. Increased Capacity: Stations that are operating over designed capacity due to system growth are targeted for replacement to maintain gas supply. Loss of Containment: Station experiencing loss of containment (leaks) and high maintenance calls to repair equipment are also identified for replacement. Asset: District station assets Related Program: N/A**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office/All	**01 - All**	Distribution Stations	**Pass**		**101552**	2029 Telemetry*	**2029**	$ 2,159,532	**Telemetry systems are required to monitor and control our pipeline system. Applicable Codes: Z662, Sec 11.26.4 provides code requirement for safe and reliable communication. The Telemetry system includes communication paths from the instrumentation at our stations to Gas Control and it allows them to monitor EGI Distribution conditions. Gas flow: For gas supply to meet nominations Leak detection: Indicated by large pressure drops Overpressure protection and Pressure Control: Condition monitoring equipment by gas control ensures gas delivery to the customers in a controlled and safe manner. Included in this program are upgrades to the Telemetry network that include: 1)Cyber Security - Ongoing upgrades to Scada system to ensure compliance with EI Cyber security standards and proposed CSA code 2)Legacy equipment - 3330 Bristol units(10/yr) must be replaced with Control Wave Micro units 3) RTU Programming Manual - Development of manual detailing programming standards for design, security and expansion 4)SCADA - Development of maintenance layer of Scada to allow site reporting of gas consumption for boiler gas, odourant pump strokes and usage tracking, boiler diagnostics, remote engineering and automation of gate/feeder stations 5)Broadband Communication - Development of broadband links between major stations to support security (i.e. intrusion detection)**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office/All	**01 - All**	Distribution Stations	**Pass**		**101553**	2030 Telemetry*	**2030**	$ 2,268,768	**Telemetry systems are required to monitor and control our pipeline system. Applicable Codes: Z662, Sec 11.26.4 provides code requirement for safe and reliable communication. The Telemetry system includes communication paths from the instrumentation at our stations to Gas Control and it allows them to monitor EGI Distribution conditions. Gas flow: For gas supply to meet nominations Leak detection: Indicated by large pressure drops Overpressure protection and Pressure Control: Condition monitoring equipment by gas control ensures gas delivery to the customers in a controlled and safe manner. Included in this program are upgrades to the Telemetry network that include: 1)Cyber Security - Ongoing upgrades to Scada system to ensure compliance with EI Cyber security standards and proposed CSA code 2)Legacy equipment - 3330 Bristol units(10/yr) must be replaced with Control Wave Micro units 3) RTU Programming Manual - Development of manual detailing programming standards for design, security and expansion 4)SCADA - Development of maintenance layer of Scada to allow site reporting of gas consumption for boiler gas, odourant pump strokes and usage tracking, boiler diagnostics, remote engineering and automation of gate/feeder stations 5)Broadband Communication - Development of broadband links between major stations to support security (i.e. intrusion detection)**	Complete	**Fail**	See investment description, IRPAs not appliable					

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Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
Head Office/All	**01 - All**	Distribution Stations	**Pass**		**101556**	2029 District Station Rebuilds Program*	**2029**	$ 9,588,011	**Issue/Concern: The stations identified in this business case fall into one of the following categories: Below-ground box replacements: Removal of below-ground stations improves life cycle cost of stations due to accelerated corrosion related to salting and flooding, increased O&M costs related to increased paint frequency, and the requirement for two at a box when work is performed. An additional and very important benefit to the elimination of below-ground boxes is the improvement of worker health and safety by eliminating the need to handle potentially contaminated water, and non-ergonomic work conditions. Obsolete Regulators: The criteria for this category is that there are no spare parts available, or parts are no longer approved for use on new installations, or a combination of poor performance and manufacturer availability. Low Pressure Districts: The failure of a low pressure district can have disastrous downstream impacts in the event of over-pressure protection failure. The outlets of these stations feed customers who may not have individual regulators at their meter sets. This additional line of defense is not present to protect customer piping. Double Boot-style Regulators: Stations with both operator and monitor boot-style regulators have a common failure mechanism as a result of debris in the gas stream. Replacement of one boot-style regulator with a non-boot regulator reduces the vulnerability of failure. Increased Capacity: Stations that are operating over designed capacity due to system growth are targeted for replacement to maintain gas supply. Loss of Containment: Station experiencing loss of containment (leaks) and high maintenance calls to repair equipment are also identified for replacement. Asset: District station assets Related Program: N/A**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office/All	**01 - All**	Distribution Stations	**Pass**		**101557**	2030 District Station Rebuilds Program*	**2030**	$ 9,875,495	**Issue/Concern: The stations identified in this business case fall into one of the following categories: Below-ground box replacements: Removal of below-ground stations improves life cycle cost of stations due to accelerated corrosion related to salting and flooding, increased O&M costs related to increased paint frequency, and the requirement for two at a box when work is performed. An additional and very important benefit to the elimination of below-ground boxes is the improvement of worker health and safety by eliminating the need to handle potentially contaminated water, and non-ergonomic work conditions. Obsolete Regulators: The criteria for this category is that there are no spare parts available, or parts are no longer approved for use on new installations, or a combination of poor performance and manufacturer availability. Low Pressure Districts: The failure of a low pressure district can have disastrous downstream impacts in the event of over-pressure protection failure. The outlets of these stations feed customers who may not have individual regulators at their meter sets. This additional line of defense is not present to protect customer piping. Double Boot-style Regulators: Stations with both operator and monitor boot-style regulators have a common failure mechanism as a result of debris in the gas stream. Replacement of one boot-style regulator with a non-boot regulator reduces the vulnerability of failure. Increased Capacity: Stations that are operating over designed capacity due to system growth are targeted for replacement to maintain gas supply. Loss of Containment: Station experiencing loss of containment (leaks) and high maintenance calls to repair equipment are also identified for replacement. Asset: District station assets Related Program: N/A**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office/All	**01 - All**	Distribution Stations	**Pass**		**501126**	FIMP Station Assessment Program*		$ 15,572,654	**Issue/Concern/Opportunity: FIMP assesses stations against threats that are listed in the EGI Hazard and Risk Common Register Risk Register to identify susceptibility to identified risks and determine mitigation strategies for individual sites, ensuring that risk is managed to the lowest practical levels. The strategy for the FIMP program is to perform inspections using with approved technologies used at EGI or other utilities for similar asset types. These inspections will assess the condition of existing station assets and will detect any concerns or issues to help determine the likelihood and consequence of failure of individual components and evaluate the risk. This strategy will allow for targeted replacement and will extend the useful life of assets by identifying condition issues prior to the occurrence of an incident. 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. Assets: FIMP DS Stations Related Investments: N/A**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office/All	**01 - All**	Distribution Stations	**Pass**		**734294**	2031 Telemetry*	**2031**	$ 2,287,935	**Telemetry systems are required to monitor and control our pipeline system. Applicable Codes: Z662, Sec 11.26.4 provides code requirement for safe and reliable communication. The Telemetry system includes communication paths from the instrumentation at our stations to Gas Control and it allows them to monitor EGI Distribution conditions. Gas flow: For gas supply to meet nominations Leak detection: Indicated by large pressure drops Overpressure protection and Pressure Control: Condition monitoring equipment by gas control ensures gas delivery to the customers in a controlled and safe manner. Included in this program are upgrades to the Telemetry network that include: 1)Cyber Security - Ongoing upgrades to Scada system to ensure compliance with EI Cyber security standards and proposed CSA code 2)Legacy equipment - 3330 Bristol units(10/yr) must be replaced with Control Wave Micro units 3) RTU Programming Manual - Development of manual detailing programming standards for design, security and expansion 4)SCADA - Development of maintenance layer of Scada to allow site reporting of gas consumption for boiler gas, odourant pump strokes and usage tracking, boiler diagnostics, remote engineering and automation of gate/feeder stations 5)Broadband Communication - Development of broadband links between major stations to support security (i.e. intrusion detection)**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office/All	**01 - All**	Distribution Stations	**Pass**		**734296**	2032 Telemetry*	**2032**	$ 2,274,064	**Telemetry systems are required to monitor and control our pipeline system. Applicable Codes: Z662, Sec 11.26.4 provides code requirement for safe and reliable communication. The Telemetry system includes communication paths from the instrumentation at our stations to Gas Control and it allows them to monitor EGI Distribution conditions. Gas flow: For gas supply to meet nominations Leak detection: Indicated by large pressure drops Overpressure protection and Pressure Control: Condition monitoring equipment by gas control ensures gas delivery to the customers in a controlled and safe manner. Included in this program are upgrades to the Telemetry network that include: 1)Cyber Security - Ongoing upgrades to Scada system to ensure compliance with EI Cyber security standards and proposed CSA code 2)Legacy equipment - 3330 Bristol units(10/yr) must be replaced with Control Wave Micro units 3) RTU Programming Manual - Development of manual detailing programming standards for design, security and expansion 4)SCADA - Development of maintenance layer of Scada to allow site reporting of gas consumption for boiler gas, odourant pump strokes and usage tracking, boiler diagnostics, remote engineering and automation of gate/feeder stations 5)Broadband Communication - Development of broadband links between major stations to support security (i.e. intrusion detection)**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office/All	**01 - All**	Distribution Stations	**Pass**		**734307**	2031 District Station Rebuilds Program*	**2031**	$ 9,763,652	**Issue/Concern: The stations identified in this business case fall into one of the following categories: Below-ground box replacements: Removal of below-ground stations improves life cycle cost of stations due to accelerated corrosion related to salting and flooding, increased O&M costs related to increased paint frequency, and the requirement for two at a box when work is performed. An additional and very important benefit to the elimination of below-ground boxes is the improvement of worker health and safety by eliminating the need to handle potentially contaminated water, and non-ergonomic work conditions. Obsolete Regulators: The criteria for this category is that there are no spare parts available, or parts are no longer approved for use on new installations, or a combination of poor performance and manufacturer availability. Low Pressure Districts: The failure of a low pressure district can have disastrous downstream impacts in the event of over-pressure protection failure. The outlets of these stations feed customers who may not have individual regulators at their meter sets. This additional line of defense is not present to protect customer piping. Double Boot-style Regulators: Stations with both operator and monitor boot-style regulators have a common failure mechanism as a result of debris in the gas stream. Replacement of one boot-style regulator with a non-boot regulator reduces the vulnerability of failure. Increased Capacity: Stations that are operating over designed capacity due to system growth are targeted for replacement to maintain gas supply. Loss of Containment: Station experiencing loss of containment (leaks) and high maintenance calls to repair equipment are also identified for replacement. Asset: District station assets Related Program: N/A**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office/All	**01 - All**	Distribution Stations	**Pass**		**734308**	2032 District Station Rebuilds Program*	**2032**	$ 9,480,179	**Issue/Concern: The stations identified in this business case fall into one of the following categories: Below-ground box replacements: Removal of below-ground stations improves life cycle cost of stations due to accelerated corrosion related to salting and flooding, increased O&M costs related to increased paint frequency, and the requirement for two at a box when work is performed. An additional and very important benefit to the elimination of below-ground boxes is the improvement of worker health and safety by eliminating the need to handle potentially contaminated water, and non-ergonomic work conditions. Obsolete Regulators: The criteria for this category is that there are no spare parts available, or parts are no longer approved for use on new installations, or a combination of poor performance and manufacturer availability. Low Pressure Districts: The failure of a low pressure district can have disastrous downstream impacts in the event of over-pressure protection failure. The outlets of these stations feed customers who may not have individual regulators at their meter sets. This additional line of defense is not present to protect customer piping. Double Boot-style Regulators: Stations with both operator and monitor boot-style regulators have a common failure mechanism as a result of debris in the gas stream. Replacement of one boot-style regulator with a non-boot regulator reduces the vulnerability of failure. Increased Capacity: Stations that are operating over designed capacity due to system growth are targeted for replacement to maintain gas supply. Loss of Containment: Station experiencing loss of containment (leaks) and high maintenance calls to repair equipment are also identified for replacement. Asset: District station assets Related Program: N/A**	Complete	**Fail**	See investment description, IRPAs not appliable					

* in the Investment Name indicates a program item. Program items are unique as they represent numerous projects grouped together and budgeted in advance. This results in forecast spend appearing larger than it would at the project level and it also impacts the in-service dates

Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
Head Office/All	**01 - All**	Distribution Stations	**Pass**		**735117**	Stations with Auxiliary Equipment Replacement Program*	**2023**	$ 160,911,407	**Issue/Concern:** **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** **Related Program: N/A**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office/All	**01 - All**	Utilization	**Fail**	Dollar threshold	**8543**	2023 Commercial / Industrial LPDMS Program*	**2023**	$ 623,456									
Head Office/All	**01 - All**	Utilization	**Fail**	Dollar threshold	**8544**	2024 Commercial / Industrial LPDMS Program*	**2024**	$ 640,688									
Head Office/All	**01 - All**	Utilization	**Fail**	Dollar threshold	**8545**	2025 Commercial / Industrial LPDMS Program*	**2025**	$ 762,124									
Head Office/All	**01 - All**	Utilization	**Fail**	Dollar threshold	**8546**	2026 Commercial / Industrial LPDMS Program*	**2026**	$ 882,683									
Head Office/All	**01 - All**	Utilization	**Fail**	Dollar threshold	**8547**	2027 Commercial / Industrial LPDMS Program*	**2027**	$ 1,042,208									
Head Office/All	**01 - All**	Utilization	**Fail**	Dollar threshold	**8804**	2023 Farm tap Program*	**2023**	$ 218,210									
Head Office/All	**01 - All**	Utilization	**Fail**	Dollar threshold	**8805**	2024 Farm tap Program*	**2024**	$ 224,241									
Head Office/All	**01 - All**	Utilization	**Fail**	Dollar threshold	**8806**	2025 Farm tap Program*	**2025**	$ 238,971									
Head Office/All	**01 - All**	Utilization	**Fail**	Dollar threshold	**8807**	2026 Farm tap Program*	**2026**	$ 274,613									
Head Office/All	**01 - All**	Utilization	**Fail**	Dollar threshold	**8808**	2027 Farm tap Program*	**2027**	$ 326,559									
Head Office/All	**01 - All**	Utilization	**Fail**	Dollar threshold	**17966**	2023 Assets Downstream of Bulk Meters*	**2023**	$ 253,634									
Head Office/All	**01 - All**	Utilization	**Fail**	Dollar threshold	**17967**	2025 Assets Downstream of Bulk Meters*	**2025**	$ 516,694									
Head Office/All	**01 - All**	Utilization	**Fail**	Dollar threshold	**17968**	2024 Assets Downstream of Bulk Meters*	**2024**	$ 260,645									
Head Office/All	**01 - All**	Utilization	**Fail**	Dollar threshold	**17969**	2026 Assets Downstream of Bulk Meters*	**2026**	$ 523,072									
Head Office/All	**01 - All**	Utilization	**Fail**	Dollar threshold	**17970**	2027 Assets Downstream of Bulk Meters*	**2027**	$ 555,844									
Head Office/All	**01 - All**	Utilization	**Fail**	Dollar threshold	**17971**	2028 Assets Downstream of Bulk Meters*	**2028**	$ 551,108									
Head Office/All	**01 - All**	Utilization	**Fail**	Dollar threshold	**101968**	2029 Assets Downstream of Bulk Meters*	**2029**	$ 547,886									
Head Office/All	**01 - All**	Utilization	**Fail**	Dollar threshold	**101970**	2028 Commercial / Industrial LPDMS Program*	**2028**	$ 1,226,214									
Head Office/All	**01 - All**	Utilization	**Fail**	Dollar threshold	**101971**	2029 Commercial / Industrial LPDMS Program*	**2028**	$ 1,219,047									
Head Office/All	**01 - All**	Utilization	**Fail**	Dollar threshold	**101972**	2028 Farm tap Program*	**2028**	$ 378,886									
Head Office/All	**01 - All**	Utilization	**Fail**	Dollar threshold	**101973**	2029 Farm tap Program*	**2029**	$ 376,672									
Head Office/All	**01 - All**	Utilization	**Fail**	Dollar threshold	**101974**	2030 Farm tap Program*	**2030**	$ 1,143,974									
Head Office/All	**01 - All**	Utilization	**Fail**	Dollar threshold	**101976**	2030 Assets Downstream of Bulk Meters*	**2030**	$ 564,314									
Head Office/All	**01 - All**	Utilization	**Pass**		**19983**	Meter Purchases- MXGI's, MXG's, MXOT's*	**2027**	$ 313,176,431	**Meters are used to determine the gas consumption input of customer billing. The replacement program for meters is mandated by Measurement Canada. The program includes: testing, repair, and replacement requirements of meters and instruments. All verified meters are approved by Measurement Canada with an issuance of a certificate which identifies that the meter complies with Electricity and Gas Specification S-EG-02. EGI must ensure all measurement devices remain in compliance for annual audits by Measurement Canada. Measurement Canada specifies tolerances under which the meter must operate in the field. EGD must demonstrate that all aspects of its meter sampling, maintenance, and replacement comply with these criteria in order to be accredited by Measurement Canada to be an "Authorized Service Provider" and adhere to Measurement Canada's accreditation standard S-A-01. Meters may also require exchange for issues such as: damages, leaks, customer billing issues.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office/All	**01 - All**	Utilization	**Pass**		**23228**	Meter Purchases- New Customer Additions*		$ 66,275,270	**New meters are required for customer expansion projects. Meters are used to determine the gas consumption input of customer billing.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office/All	**01 - All**	Utilization	**Pass**		**101975**	2030 Commercial / Industrial LPDMS Program*	**2030**	$ 3,702,314	**These meter sets primarily serve commercial, industrial, and high density residential customers, typically with a meter > 400 series. They require proper operation to ensure gas does not exceed supply pressure. These sets consist of regulator(s), relief(s), riser, and meter. Failure of the regulation system has the potential to cause an over pressure to the customer's supply line and appliances. Over-pressure can result in a loss of containment within the building making the event of ignition, fire, and explosion possible. The condition of these Commercial/Industrial LPDMS is largely unknown. They have not been part of pro-active inspection programs. A survey on a sample population indicated a number of potential issues including: - Old Regulators - Corrosion of piping and regulators - Non-Adherence to installation specifications**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office/All	**01 - All**	Utilization	**Pass**		**738580**	Meter Purchases- MXGI's, MXG's, MXOT's*		$ 115,594,243	**Meter & Reg Install- Replacement**	Complete	**Fail**	See investment description, IRPAs not appliable					
Head Office/All	**Div_54 - Head Office Support**	Growth	**Pass**	(blank)	**736972**	Hydrogen Fuel Heating Systems Feasibility Assessment	**2025**	$ 2,334,906	**Issue/Concern/Opportunity: The feasibility study would explore two items:** **1.Blending of hydrogen at gate and transmission regulating stations with the potential for on-site production of hydrogen. The study will quantify the maximum practical limits of hydrogen that can be blended into the natural gas fuel source of existing boiler systems.** **2.Identifying the optimal site for a pilot project that will use an integrated pilot plant based on the availability of excess electricity and an opportunity to balance the demands on the electrical grid, availability of land for on-site hydrogen production and storage, and general operating conditions.** **EGI will review 35 of its roughly 165 boiler facilities as part of its mainline Dawn-Parkway gas transmission system and associated downstream distribution stations. These stations regulate EGI's transmission gas pressures to lower distribution pressures to safely feed the Ontario natural gas distribution area. Due to the cooling of gas while regulating a high-pressure cut from transmission to lower distribution pressures, heat is required to mitigate the possible damage of the cooling effect to ensure safe and reliable operations for customers.** **Additionally, the study will evaluate feasibility and alternatives for procurement or production of hydrogen as required to supply current boiler systems through Combined Heat & Power (CHP) applications where hydrogen will be used as the fuel source for boilers and the waste heat generated during hydrogen production is captured to maximize energy efficiency.** **Assets: EGI will review 35 of its roughly 165 boiler facilities as part of its mainline Dawn-Parkway gas transmission system and associated downstream distribution stations** **Related Program: 736973 - Hydrogen for Compression Facilities Feasibility Assessment**	Planned							

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Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
Head Office/All	Div_54 - Head Office Support	Growth	Pass	(blank)	736973	Hydrogen for Compression Facilities Feasibility Assessment	2025	$ 1,640,842	Issue/Concern/Opportunity: The proposed feasibility study will: 1.Review the current compressor fleet, identify current and future projected fuel requirements, and evaluate the impact of varying hydrogen concentrations on turbine operations, emissions, safety and reliability. 2.Explore the requirements for partial conversion to hydrogen fuel with current equipment, with minor equipment upgrades, and with major upgrades to facilitate an envisioned 100% pure hydrogen fuel source. 3.Conduct a cost-benefit analysis to support a technically and economically feasible hydrogen transition. 4.Establish a strategy for hydrogen generation and conversion of the compressor fleet. 5.Refine company standards, policies and procedures to ensure continued safe, reliable and affordable operations. Assets: The feasibility study will evaluate the five major compressor sites along EGI's Dawn-Parkway mainline transmission system: 1.Dawn Hub - Centred at 3332 Bentpath Line, Dawn-Euphemia, ON - 9 turbines totalling 189 MW 2.Lobo Compressor (14M-601) - 11025 Ivan Drive, Ilderton, ON - 5 turbines totalling 124 MW 3.Bright Compressor (16S-101) - 866139 Twp. Rd. #10, Bright, ON - 4 turbines totalling 115 MW 4.Parkway West Compressor (20Y-407) - 6699 8th Line, Milton, ON - 2 turbines totalling 66 MW 5.Parkway East Compressor (20Y-404) - 6626 9th Line, Missisauga, ON - 2 turbines totalling 50 MW Related Program: 736972 - Hydrogen Fuel Heating Systems Feasibility Assessment	Planned							
Head Office/All	Div_54 - Head Office Support	Growth	Pass	(blank)	736974	Hydrogen Blending Phase 2	2026	$ 9,050,523	The second part of the hydrogen blending project LCEP 1 . It will expand blended gas with hydrogen at 2% supplied to an additional 12400 customers approximately	Planned							
Head Office/All	Div_54 - Head Office Support	Growth	Pass	(blank)	736975	Enbridge Gas Distribution System Hydrogen Feasibility Study		$ 15,523,163	Comprehensive techno-economic feasibility study of blending hydrogen into Enbridge Gas Inc.'s (EGI) existing natural gas distribution and transmission network across Ontario. Evaluate the technical feasibility and maximum limits of blended hydrogen gas in existing networks,identify necessary retrofits or upgrades for varying concentrations of hydrogen, and develop a staged roadmap for transitioning Ontario's gas network to a low-carbon future in line with technical and economic barriers and opportunities. The assessment comprises the entirety of EGI's gas pipeline network in Ontario. By blending hydrogen at strategic locations across EGI's existing gas network, EGI aims to reduce the carbon intensity of its 3.8 million residential, commercial, institutional and industrial customers across over 500 communities in Ontario.	Planned							
Northern	Div_33 - Thunder Bay	Distribution Pipe	Fail	Dollar threshold	1268	Thunder Bay Loop Retrofit		$ 809,595									
Northern	Div_33 - Thunder Bay	Distribution Pipe	Fail	Dollar threshold	48507	THUN: Dist-Repl-Compy-Mains Municipal*	2020	$ 3,221,779									
Northern	Div_33 - Thunder Bay	Distribution Pipe	Fail	Dollar threshold	48508	THUN: Dist-Repl-Compy-Mains Leakage*	2020	$ 8,390,461									
Northern	Div_33 - Thunder Bay	Distribution Pipe	Fail	Dollar threshold	48509	THUN: Dist-Repl-Compy-Services*	2020	$ 3,035,773									
Northern	Div_33 - Thunder Bay	Distribution Pipe	Fail	Dollar threshold	48511	THUN: Land Rights-Replacements	2023	$ 3,737									
Northern	Div_33 - Thunder Bay	Distribution Pipe	Fail	Dollar threshold	48515	THUN: Indirect Materials-Replacements	2023	$ 55,036									
Northern	Div_33 - Thunder Bay	Distribution Pipe	Fail	Dollar threshold	48524	TBAY: 33-21-600 Centennial Park Exposed NPS 8	2023	$ 769,051									
Northern	Div_33 - Thunder Bay	Distribution Pipe	Fail	Dollar threshold	49507	TBAY: 33-22-600 Atikokan Lateral - TP8 -Leak	2023	$ 529,350									
Northern	Div_33 - Thunder Bay	Distribution Pipe	Fail	Dollar threshold	49509	Atikokan Steep Rock Mine Valve Nest Retirement	2031	$ 139,928									
Northern	Div_33 - Thunder Bay	Distribution Pipe	Fail	Dollar threshold	49510	Darlington Bay Bridge - NPS 2 Replacement	2025	$ 1,291,450									
Northern	Div_33 - Thunder Bay	Distribution Pipe	Fail	Dollar threshold	501009	THUN: PSLL Maintenance	2023	$ 175,579									
Northern	Div_33 - Thunder Bay	Distribution Pipe	Fail	Dollar threshold	503015	TBAY: 33-22-601 Atikokan Lateral Leak Dwnst of Sapawe Mill	2031	$ 536,347									
Northern	Div_33 - Thunder Bay	Distribution Pipe	Fail	Dollar threshold	503375	TBAY: Kenora 9 Brinkman Rectifier		$ 68,504									
Northern	Div_33 - Thunder Bay	Distribution Pipe	Fail	Dollar threshold	503376	TBAY: Kenora 9 Rupert at Ninth Rectifier		$ 68,504									
Northern	Div_33 - Thunder Bay	Distribution Pipe	Fail	Dollar threshold	734922	NPS 8 Redlake Retrofit		$ 1,303,223									
Northern	Div_33 - Thunder Bay	Distribution Pipe	Fail	Dollar threshold	735679	45-22-000 TIMM Grierson Rd Valve Replacement	2023	$ 56,049									
Northern	Div_33 - Thunder Bay	Distribution Pipe	Pass		1266	Redrock Retrofit		$ 1,718,832	Project-Specific: External Corrosion Direct Assessment (ECDA) to In-Line Inspection (ILI) Program, supporting refinement of pipeline risk profile. Associated 2024 Operations and Maintenance (O&M) spend for ILI. 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% Specified Minimum Yield Strength (SMYS). It includes installation costs for permanent 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 that are identified through the inspections.	Complete	Fail	See investment description, IRPAs not appliable					
Northern	Div_33 - Thunder Bay	Distribution Pipe	Pass		30134	4th Ave S-Kenora-1562	2031	$ 4,954,127	4th Ave. S. - Kenora - 1562 Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.	Planned							
Northern	Div_33 - Thunder Bay	Distribution Pipe	Pass		30136	Arthur St W -Thunder Bay-1496	2027	$ 4,182,490	Arthur St. W. -Thunder Bay - 1496 Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization. Comments: There is a fault associated with the area.	Planned							

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Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
Northern	**Div_33 - Thunder Bay**	Distribution Pipe	**Pass**		**30142**	Dominion Ave 2-Kapuskasing-1540	**2031**	$ 2,481,933	**Dominion Ave. 2 - Kapuskasing - 1540** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
Northern	**Div_33 - Thunder Bay**	Distribution Pipe	**Pass**		**30143**	Dominion Ave-Kapuskasing-1499	**2030**	$ 5,091,521	**Dominion Ave. – Kapuskasing - 1499** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
Northern	**Div_33 - Thunder Bay**	Distribution Pipe	**Pass**		**30144**	Finlayson St-Thunder Bay-1563	**2031**	$ 3,175,990	**Finlayson St. - Thunder Bay - 1563** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Complete	**Fail**	NPS 2, cannot downsize or retire					
Northern	**Div_33 - Thunder Bay**	Distribution Pipe	**Pass**		**30145**	George St-Hearst-1558	**2032**	$ 5,437,097	**George St. - Hearst - 1558** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
Northern	**Div_33 - Thunder Bay**	Distribution Pipe	**Pass**		**30146**	Hart St-Timmins -1559	**2032**	$ 4,955,639	**Hart St. - Timmins (moratorium until 2025) -1559** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: City will not allow work on Toke St. within the next five years as it was reconstructed in 2020. Moratorium is until 2025.**	Planned							
Northern	**Div_33 - Thunder Bay**	Distribution Pipe	**Pass**		**30151**	Marks St S-Thunder Bay-1537	**2029**	$ 5,500,549	**Marks St. S. - Thunder Bay - 1537** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
Northern	**Div_33 - Thunder Bay**	Distribution Pipe	**Pass**		**30155**	Ogden St-Thunder Bay-1568	**2030**	$ 5,556,674	**Ogden St. - Thunder Bay - 1568** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
Northern	**Div_33 - Thunder Bay**	Distribution Pipe	**Pass**		**30156**	Prince Arthur Blvd-Thunder Bay-1538	**2031**	$ 4,043,057	**Prince Arthur Blvd. - Thunder Bay - 1538** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
Northern	**Div_33 - Thunder Bay**	Distribution Pipe	**Pass**		**30157**	Seventh Ave N-Kenora-1546	**2031**	$ 4,237,285	**Seventh Ave. N. - Kenora - 1546** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
Northern	**Div_33 - Thunder Bay**	Distribution Pipe	**Pass**		**30158**	Seventh St S-Kenora-1542	**2032**	$ 3,823,134	**Seventh St. S. - Kenora - 1542** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
Northern	**Div_33 - Thunder Bay**	Distribution Pipe	**Pass**		**30160**	Spruce St-Kapuskasing-1565	**2029**	$ 5,024,951	**Spruce St. - Kapuskasing - 1565** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Complete	**Fail**	NPS 2, cannot downsize or retire					

* in the Investment Name indicates a program item. Program items are unique as they represent numerous projects grouped together and budgeted in advance. This results in forecast spend appearing larger than it would at the project level and it also impacts the in-service dates

Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
Northern	**Div_33 - Thunder Bay**	Distribution Pipe	**Pass**		**48517**	THUN: Anodes*	**2020**	$ 10,076,231	**General: The anodes program within the corrosion program includes the required expenditure to install anodes in order to reduce the amount of down plant within EGI's 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.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Northern	**Div_33 - Thunder Bay**	Distribution Pipe	**Pass**		**49256**	NW_Lateral Clamp Cut Outs_ATIKOKAN	**2031**	$ 3,078,413	**General: 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.**	Planned							
Northern	**Div_33 - Thunder Bay**	Distribution Pipe	**Pass**		**503071**	Northern Region: Corrosion Rectifier Groundbed Program*	**2021**	$ 1,514,984	**General: The corrosion program includes the expenditure other than anodes required to reduce the amount of down plant within EGI's 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. Individual projects will be set up to use these program dollars based on identification of rectifier and groundbed sites by the Corrosion group.** **Cloned inv #101794 to seperate due to boundary realignment in Northern Region vs 2020 investment creation date.. Updated name to identify as district planning blanket and reflect how forecast will be provided for budgeting. Program items will be named/numbered according to Division where work is performed.** **2021 Forecast will also be adjusted from original placeholder value under Inv #101794** **2022 Budget will be allocated based on split of forecast**	Complete	**Fail**	See investment description, IRPAs not appliable					
Northern	**Div_33 - Thunder Bay**	Distribution Pipe	**Pass**		**734020**	NPS 8 Onion Lake Lateral Replacement		$ 1,868,295	**Project-Specific: External Corrosion Direct Assessment (ECDA) to In-Line Inspection (ILI) Program, supporting refinement of pipeline risk profile. The entire ~320m Onion Lake Lateral is proposed for replacement between TCE and Onion Lake Primary Station (30201002).** **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% Specified Minimum Yield Strength (SMYS). It includes installation costs for permanent 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 that are identified through the inspections.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Northern	**Div_33 - Thunder Bay**	Distribution Pipe	**Pass**		**734021**	NPS 8 Onion Lake Loop Retrofit		$ 1,868,295	**Project-Specific: External Corrosion Direct Assessment (ECDA) to In-Line Inspection (ILI) Program, supporting refinement of pipeline risk profile. Associated 2024 Operations and Maintenance (O&M) spend for ILI.** **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% Specified Minimum Yield Strength (SMYS). It includes installation costs for permanent 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 that are identified through the inspections.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Northern	**Div_33 - Thunder Bay**	Distribution Stations	**Fail**	Dollar threshold	**48504**	TBAY & TIMM: Plan(T)-Dist-Stn Measuring/Corrosion Stn*	**2020**	$ 261,453									
Northern	**Div_33 - Thunder Bay**	Distribution Stations	**Fail**	Dollar threshold	**48527**	TBAY: Clark & Niven DRS Rebuild	**2024**	$ 640,809									
Northern	**Div_33 - Thunder Bay**	Distribution Stations	**Fail**	Dollar threshold	**100938**	TBAY: Dryden Domtar SMS, Station Modifications	**2030**	$ 282,950									
Northern	**Div_33 - Thunder Bay**	Distribution Stations	**Fail**	Dollar threshold	**100945**	TBAY: Longlac TBS, Heater Replacement	**2024**	$ 258,040									
Northern	**Div_33 - Thunder Bay**	Distribution Stations	**Fail**	Dollar threshold	**102993**	TBAY: Martha at Red River Station Rebuild	**2026**	$ 1,042,578									
Northern	**Div_33 - Thunder Bay**	Distribution Stations	**Fail**	Dollar threshold	**502824**	TBAY: Kraft SMS Retirement	**2030**	$ 226,360									
Northern	**Div_33 - Thunder Bay**	Distribution Stations	**Fail**	Dollar threshold	**503274**	NW PFM Compliance Program*		$ 237,010									
Northern	**Div_33 - Thunder Bay**	Distribution Stations	**Fail**	Dollar threshold	**733372**	TBAY: Wright at O'Brien DRS Pipe Supports	**2030**	$ 28,295									
Northern	**Div_33 - Thunder Bay**	Distribution Stations	**Fail**	Dollar threshold	**733375**	TBAY: New Station at Mercury Ave & Maple Station Retirement (Atikokan)	**2025**	$ 968,588									
Northern	**Div_33 - Thunder Bay**	Distribution Stations	**Fail**	Dollar threshold	**733772**	TBAY: Vermillion Bay PCS, Boiler Replacement	**2027**	$ 269,222									
Northern	**Div_33 - Thunder Bay**	Distribution Stations	**Fail**	Dollar threshold	**733865**	TBAY: Kenora TBS, Boiler Replacement	**2028**	$ 222,940									
Northern	**Div_33 - Thunder Bay**	Distribution Stations	**Fail**	Dollar threshold	**733866**	TBAY: McIrvine TBS, Boiler Replacement	**2029**	$ 151,662									
Northern	**Div_33 - Thunder Bay**	Distribution Stations	**Fail**	Dollar threshold	**733867**	TBAY: Ignace TBS, Boiler Replacement	**2029**	$ 151,662									
Northern	**Div_33 - Thunder Bay**	Distribution Stations	**Fail**	Dollar threshold	**733869**	TBAY: Belrose PCS, Boiler Replacement	**2029**	$ 956,425									
Northern	**Div_33 - Thunder Bay**	Distribution Stations	**Fail**	Dollar threshold	**733870**	TBAY: Nipigon TBS, Boiler Replacement	**2030**	$ 165,526									
Northern	**Div_33 - Thunder Bay**	Distribution Stations	**Fail**	Dollar threshold	**733872**	TBAY: Balmertown - Goldcorp SMS, Boiler Replacement	**2030**	$ 253,240									
Northern	**Div_33 - Thunder Bay**	Distribution Stations	**Fail**	Dollar threshold	**733875**	TBAY: Geraldton TBS, Boiler Replacement	**2032**	$ 183,329									
Northern	**Div_33 - Thunder Bay**	Distribution Stations	**Fail**	Dollar threshold	**733876**	TBAY: Kenora Airport Rd, Boiler Replacement	**2032**	$ 183,329									
Northern	**Div_33 - Thunder Bay**	Distribution Stations	**Fail**	Dollar threshold	**734565**	TBAY: 500 Toledo St MUB Rebuild	**2023**	$ 186,830									
Northern	**Div_33 - Thunder Bay**	Distribution Stations	**Fail**	Dollar threshold	**735629**	TBAY: Fisher 621 PRS Rebuild Program*	**2026**	$ 977,417									
Northern	**Div_33 - Thunder Bay**	Distribution Stations	**Fail**	Dollar threshold	**735631**	TBAY: Paquette Road Station Rebuild	**2026**	$ 977,417									
Northern	**Div_33 - Thunder Bay**	Distribution Stations	**Fail**	Dollar threshold	**735632**	TBAY: Burwood Rd TBS Filter	**2032**	$ 135,799									
Northern	**Div_33 - Thunder Bay**	Distribution Stations	**Fail**	Dollar threshold	**735633**	TBAY: Balsam St TBS Filter	**2025**	$ 129,145									
Northern	**Div_33 - Thunder Bay**	Distribution Stations	**Fail**	Dollar threshold	**735634**	TBAY: Dewe St DRS Relocation	**2031**	$ 839,567									
Northern	**Div_33 - Thunder Bay**	Distribution Stations	**Fail**	Dollar threshold	**735635**	TBAY: Mountdale at Francis DRS Rebuild	**2032**	$ 814,795									
Northern	**Div_33 - Thunder Bay**	Distribution Stations	**Fail**	Dollar threshold	**735669**	TBAY: 2022 Morecombe PRS (at Onion Lk) Rebuild	**2023**	$ 24,911									
Northern	**Div_33 - Thunder Bay**	Distribution Stations	**Fail**	Dollar threshold	**735707**	THUN: Gorevale Road PRS Station Relocation	**2031**	$ 839,567									
Northern	**Div_33 - Thunder Bay**	Distribution Stations	**Fail**	Dollar threshold	**735729**	TBAY: Arthur St at Cooper Rd PRS Rebuild	**2031**	$ 1,049,459									

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Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
Northern	Div_33 - Thunder Bay	Distribution Stations	Pass		100917	TBAY: 33-22-700 Dryden TBS, Glycol and Odorant Upgrades	2023	$ 2,117,401	Issue/Concern/Opportunity: Due to new standards, there is need to relocate below-grade glycol lines to above-grade. Also, the replacement/relocation of separate odourant bulk and pump buildings with combined structure/building is required. This would facilitate removal of above-grade odourant gravity feed between buildings and below-grade odourant injection line. The most likely risk is the increased risk of a significant environmental incident. The worst-case scenario is leakage of the below-grade boiler glycol lines or odourant injection lines, either of which would cause significant environmental concerns. Assets: Station ID 30101001, Dryden Town Border Station (TBS) Related Program: Not applicable.	Planned							
Northern	Div_33 - Thunder Bay	Distribution Stations	Pass		100918	TBAY: 33-23-700 Arthur St TBS, Thunder Bay, Station Rebuild	2024	$ 2,563,237	Issue/Concern/Opportunity: Based on 2021 Stations Engineering review, a full station rebuild is required including new inlet filter, ERX telemetry, and a CWT 1155. Station material estimate alone was $900,000. Alliance Partner. The most likely risk is regulation failure. The worst case scenario is significant system outage, as Thunder Bay North system backbone pipelines all lead to this station. Also, this station lies at the quadrant of a major MTO intersection. Assets: Station ID 30202014 Related Program: There are no related C55 investments.	Planned							
Northern	Div_33 - Thunder Bay	Distribution Stations	Pass		503174	TBAY: English River PCS Station Rebuild	2029	$ 2,049,482	Issue/Concern/Opportunity: Station alterations need to have pilot heat, larger relief valve and larger trims due to TC Energy work. Assets: Station #30701001. Related Investments: Not applicable.	Planned							
Northern	Div_33 - Thunder Bay	Growth	Pass		48506	TBAY: Company Program - New Business - Scattered Mains - Company*	2020	$ 3,643,105	Scattered Mains	Planned							
Northern	Div_33 - Thunder Bay	Growth	Pass		500424	TBAY: Company Program - Customer Connections*		$ 16,175,436	Thunder Bay Customer Connections Program Items	Planned							
Northern	Div_33 - Thunder Bay	Growth	Pass		734531	THUN: Rosslyn Rd at Sideroad 20 Reinforcement Project	2031	$ 174,910	Issue/Concern/Opportunity: •Approximately 130 m 2-inch PE main extension is to tie together two existing 420 kPa systems. •The Goal is to abandon 30206036 STN (Rosslyn Rd. at 20th Side Rd.) and small customer station south of there. •Customers currently fed by this station will then be tied to the neighbouring 420 kPa system fed by 30206035 Station (Rosslyn Rd. at Almira Post Regulation Station [PRS]) and 30206034 Station (Rosslyn Rd. at R.S. Piper). Assets: Stations 30206036, 30206025, and 30206034 Related Program: None.	Planned							
Northern	Div_33 - Thunder Bay	Utilization	Pass		48513	TBAY: Meter & Regulator Inst Repl-Company*	2020	$ 8,731,453	Meter & Reg Install- Replacement	Complete	Fail	See investment description, IRPAs not appliable					
Northern	Div_43 - Sudbury & S.S. Marie	Distribution Pipe	Fail	Dollar threshold	1275	Espanola Retrofit		$ 934,148									
Northern	Div_43 - Sudbury & S.S. Marie	Distribution Pipe	Fail	Dollar threshold	48534	SUDB: Dist-Repl-Contr-Services*	2020	$ 2,204,560									
Northern	Div_43 - Sudbury & S.S. Marie	Distribution Pipe	Fail	Dollar threshold	48544	SUDB: Land Rights-Replacements	2023	$ 6,228									
Northern	Div_43 - Sudbury & S.S. Marie	Distribution Pipe	Fail	Dollar threshold	48548	SUDB: Misc Materials-Company	2023	$ 6,228									
Northern	Div_43 - Sudbury & S.S. Marie	Distribution Pipe	Fail	Dollar threshold	48549	SUDB: Anodes*	2020	$ 329,312									
Northern	Div_43 - Sudbury & S.S. Marie	Distribution Pipe	Fail	Dollar threshold	48553	NE: Whittaker St., Sudbury, Replacement	2028	$ 443,950									
Northern	Div_43 - Sudbury & S.S. Marie	Distribution Pipe	Fail	Dollar threshold	49628	SSM: Goulais Rd Main replacement SSM	2030	$ 1,492,561									
Northern	Div_43 - Sudbury & S.S. Marie	Distribution Pipe	Fail	Dollar threshold	49641	SUDB: Gagnon St Lateral, Azilda	2031	$ 209,892									
Northern	Div_43 - Sudbury & S.S. Marie	Distribution Pipe	Fail	Dollar threshold	49645	116 Simmons Rd, Dowling PLPR	2024	$ 44,857									
Northern	Div_43 - Sudbury & S.S. Marie	Distribution Pipe	Fail	Dollar threshold	49652	NE: New Sudbury Mall Rooftop Main Coating	2023	$ 293,628									
Northern	Div_43 - Sudbury & S.S. Marie	Distribution Pipe	Fail	Dollar threshold	49653	SUDB: Regent St grasshopper, Sudbury	2027	$ 381,629									
Northern	Div_43 - Sudbury & S.S. Marie	Distribution Pipe	Fail	Dollar threshold	49666	863 Attlee St shallow main, Sudbury	2030	$ 113,180									
Northern	Div_43 - Sudbury & S.S. Marie	Distribution Pipe	Fail	Dollar threshold	49670	Bay St. Roof top piping blocking Replacement and Maintenance, SSM	2024	$ 96,121									
Northern	Div_43 - Sudbury & S.S. Marie	Distribution Pipe	Fail	Dollar threshold	49673	Kingsmount Blvd, Bannister Tees Replacement, SSM	2023	$ 112,098									
Northern	Div_43 - Sudbury & S.S. Marie	Distribution Pipe	Fail	Dollar threshold	100737	NE: Southview & Martindale, Sudbury, Valve Nest Repl	2023	$ 87,187									
Northern	Div_43 - Sudbury & S.S. Marie	Distribution Pipe	Fail	Dollar threshold	734394	SUDB: Fourth Avenue, Sudbury Damage	2023	$ 73,615									
Northern	Div_43 - Sudbury & S.S. Marie	Distribution Pipe	Fail	Dollar threshold	734593	SUDB: Bancroft Dr and Bellevue Ave, Valves Replacement	2023	$ 373,659									
Northern	Div_43 - Sudbury & S.S. Marie	Distribution Pipe	Fail	Dollar threshold	734613	SUDB: Martindale Road, Sudbury Replacement	2023	$ 112,098									
Northern	Div_43 - Sudbury & S.S. Marie	Distribution Pipe	Fail	Dollar threshold	734615	NE: Second Ave & Centre St, Espanola, Valve Replacement	2023	$ 118,325									
Northern	Div_43 - Sudbury & S.S. Marie	Distribution Pipe	Fail	Dollar threshold	734616	NE: Wellington St, SSM, Replacement	2024	$ 121,754									
Northern	Div_43 - Sudbury & S.S. Marie	Distribution Pipe	Fail	Dollar threshold	735465	SUD: Copper Cliff Replacement	2031	$ 1,708,519									
Northern	Div_43 - Sudbury & S.S. Marie	Distribution Pipe	Fail	Timing	736530	Sudbury Lateral Integrity Digs 2023	2023	$ 12,455,303				Within 3 years, supply side not applicable					
Northern	Div_43 - Sudbury & S.S. Marie	Distribution Pipe	Fail	Timing	736531	Sudbury Lateral Integrity Digs 2024	2024	$ 7,433,386				Within 3 years, supply side not applicable					

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Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
Northern	Div_43 - Sudbury & S.S. Marie	Distribution Pipe	Pass		2142	Sudbury Section 1 Sturgeon River	2023	$ 2,241,955	Issue/Concern - Replace 236 m of NPS 10 steel transmission piping from the intersection of Delorme Street and Smiley Road to approximately 275 m south of Smiley Road Main Line Valve (MLV). Chainage 43236 – 43472. Class 1 to Class 2 change. General: 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. Prework and execution capital dollars will cover the whole scope of North and South side. Assets: Sudbury Section 1 Sturgeon River. Related Programs: Not applicable.	Planned							
Northern	Div_43 - Sudbury & S.S. Marie	Distribution Pipe	Pass		734812	SUDB: RR 15 Property Line, Chelmsford, Replacement	2031	$ 2,098,918	General: 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. Issue/Concern/Opportunity: The base of the issue at this site is risk related. There are ~108 first stage cuts at this location that are off the NPS 6 main 3723 kPa MOP (540 psi). There have been several leak replacements completed over the years as the risers end up corroding as the first stage cuts are not maintained. Section from 1 to 4: Install 4'' PE main from PRS #43202212 to Rouleau Rd. Tie-in required at Montee Principale Ave (FID# 551962868) and Rouleau Rd (FID# 552034281). Total length ~4000m . Modification required at PRS 43202212 to increase its capacity slightly. Abandon PRS #43202146. Section 5: Install 4'' PE main from PRS #43202147 to 3485 RR15. Total length ~850m . Section from 6 to 7: Extend 4'' PE FID# 551830660 west on the southern side of the road & 2' PE on northern side of the road to PRS #43202147. The total length ~1920m Justification: modification required at some PRS to increase its capacity, to meet the expansion demand and growth, and to meet current Enbridge standards. Ensures the integrity of Enbridge assets and the safety of those working around the gas lines in the future. Assets: As shown above	Planned							
Northern	Div_43 - Sudbury & S.S. Marie	Distribution Stations	Fail	Dollar threshold	49611	NE: 43202064 Vale Divisional Shops PRS Replacement	2025	$ 478,312									
Northern	Div_43 - Sudbury & S.S. Marie	Distribution Stations	Fail	Dollar threshold	49678	McCreedy West Stn., Sudbury	2031	$ 27,986									
Northern	Div_43 - Sudbury & S.S. Marie	Distribution Stations	Fail	Dollar threshold	49894	NE: 43202063 - Vale Engineering & Exploration, Rebuild/Relocation	2027	$ 284,487									
Northern	Div_43 - Sudbury & S.S. Marie	Distribution Stations	Fail	Dollar threshold	101068	NE: 13403001 - Vale Totten Mine, Rebuild	2025	$ 1,087,200									
Northern	Div_43 - Sudbury & S.S. Marie	Distribution Stations	Fail	Dollar threshold	101072	NE: 43501002 - Coniston DRS, Rebuild	2023	$ 608,436									
Northern	Div_43 - Sudbury & S.S. Marie	Distribution Stations	Fail	Dollar threshold	501160	NE: 43202054 Inco Smelter, Station Modifications	2025	$ 452,008									
Northern	Div_43 - Sudbury & S.S. Marie	Distribution Stations	Fail	Dollar threshold	501161	NE: 43202154 - Bil-Mur PRS, Rebuild	2025	$ 258,290									
Northern	Div_43 - Sudbury & S.S. Marie	Distribution Stations	Fail	Dollar threshold	502659	NE: 45101125 - Essar #7 BF SMS, Gear Operator	2023	$ 12,455									
Northern	Div_43 - Sudbury & S.S. Marie	Distribution Stations	Fail	Dollar threshold	502660	NE: 45103001 - Airport Rd TBS and DRS, Boiler Replacement	2024	$ 512,647									
Northern	Div_43 - Sudbury & S.S. Marie	Distribution Stations	Fail	Dollar threshold	502661	NE: 45401095 - Great Northern Rd TBS, Boiler Replacement	2023	$ 373,659									
Northern	Div_43 - Sudbury & S.S. Marie	Distribution Stations	Fail	Dollar threshold	733753	SUD: Lasalle TBS, Boiler Replacement	2023	$ 193,057									
Northern	Div_43 - Sudbury & S.S. Marie	Distribution Stations	Fail	Dollar threshold	733754	SUD: Frood TBS, Boiler Replacement	2023	$ 158,182									
Northern	Div_43 - Sudbury & S.S. Marie	Distribution Stations	Fail	Dollar threshold	733755	SUD: Inco Smelter SMS, Boiler Replacement	2023	$ 240,387									
Northern	Div_43 - Sudbury & S.S. Marie	Distribution Stations	Fail	Dollar threshold	733756	SSM: Goulais Ave TBS Algoma 4, Boiler Replacement	2025	$ 968,588									
Northern	Div_43 - Sudbury & S.S. Marie	Distribution Stations	Fail	Dollar threshold	733762	SUD: Barrydowne, Boiler Replacement	2026	$ 234,580									
Northern	Div_43 - Sudbury & S.S. Marie	Distribution Stations	Fail	Dollar threshold	733763	SUD: Kelly Lake TBS, Boiler Replacement	2025	$ 189,843									
Northern	Div_43 - Sudbury & S.S. Marie	Distribution Stations	Fail	Dollar threshold	733765	SUD: Chelmsford, Boiler Replacement	2027	$ 213,712									
Northern	Div_43 - Sudbury & S.S. Marie	Distribution Stations	Fail	Dollar threshold	733767	SUD: Maley Dr TBS, Boiler Replacement	2026	$ 200,696									
Northern	Div_43 - Sudbury & S.S. Marie	Distribution Stations	Fail	Dollar threshold	733813	SUD: Coniston TBS, Boiler Replacement	2028	$ 145,875									
Northern	Div_43 - Sudbury & S.S. Marie	Distribution Stations	Fail	Dollar threshold	733814	SUD: Walden TBS, Boiler Replacement	2028	$ 145,875									
Northern	Div_43 - Sudbury & S.S. Marie	Distribution Stations	Fail	Dollar threshold	733841	SUD: Copper Cliff TBS, Boiler Replacement	2031	$ 172,111									
Northern	Div_43 - Sudbury & S.S. Marie	Distribution Stations	Fail	Dollar threshold	733843	NE: Espanola DRS & Domtar SMS, Station Rebuild	2028	$ 1,651,410									
Northern	Div_43 - Sudbury & S.S. Marie	Distribution Stations	Fail	Dollar threshold	733852	SSM: Elliot Lake TBS, Boiler Replacement	2031	$ 263,064									
Northern	Div_43 - Sudbury & S.S. Marie	Distribution Stations	Fail	Dollar threshold	733853	SUD: Inco North Mine SMS, Boiler Replacement	2032	$ 175,181									
Northern	Div_43 - Sudbury & S.S. Marie	Distribution Stations	Fail	Dollar threshold	733854	SSM: Blind River TBS, Boiler Replacement	2032	$ 267,524									
Northern	Div_43 - Sudbury & S.S. Marie	Distribution Stations	Fail	Dollar threshold	733856	SUD: Kukagami TBS, Boiler Replacement	2032	$ 175,181									
Northern	Div_43 - Sudbury & S.S. Marie	Distribution Stations	Fail	Dollar threshold	733857	SUD: Azilda DRS, Boiler Replacement	2032	$ 175,181									
Northern	Div_43 - Sudbury & S.S. Marie	Distribution Stations	Fail	Dollar threshold	734400	NE: 43204045 - Charlotte PRS, station rebuild	2023	$ 346,941									
Northern	Div_43 - Sudbury & S.S. Marie	Distribution Stations	Fail	Dollar threshold	734581	NE: 43204008 - Brierwood & Kelly Lake Rd PRS, Station Retirement	2024	$ 38,449									
Northern	Div_43 - Sudbury & S.S. Marie	Distribution Stations	Fail	Dollar threshold	734582	NE: 44301018 - Levack Mine Air Heater #2 SMS, Station Retirement	2027	$ 69,387									

Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
Northern	Div_43 - Sudbury & S.S. Marie	Distribution Stations	Fail	Dollar threshold	734583	NE: 43202139 - First Nickel SMS, Station Retirement	2032	$ 114,908									
Northern	Div_43 - Sudbury & S.S. Marie	Distribution Stations	Fail	Dollar threshold	736079	SSM: Goulais Ave TBS Algoma 4, Station Modifications	2031	$ 69,964									
Northern	Div_43 - Sudbury & S.S. Marie	Distribution Stations	Fail	Dollar threshold	736082	NE: 45101001 - Sault Primary, Control Valve Modifications	2030	$ 247,581									
Northern	Div_43 - Sudbury & S.S. Marie	Distribution Stations	Fail	Dollar threshold	736083	NE: 43201030 - Coniston Primary, Control Valve Modifications	2026	$ 293,225									
Northern	Div_43 - Sudbury & S.S. Marie	Growth	Pass		48539	SUDB: Company Program - New Business - Scattered Mains - Company*	2020	$ 752,037	Scattered mains	Planned							
Northern	Div_43 - Sudbury & S.S. Marie	Growth	Pass		30523	SRP_North_Parry Sound_Seguin Trail_Reinforcement_NPS6_8500m_4960kPa	2032	$ 23,764,847	Looping of existing NPS 4 main with NPS 6 for 8.5km	In Progress							
Northern	Div_43 - Sudbury & S.S. Marie	Growth	Pass		30524	SRP_North_Sault Ste Marie_45103001STN_Rebuild	2024	$ 1,796,829	Station is flowing over capacity.	Planned							
Northern	Div_43 - Sudbury & S.S. Marie	Growth	Pass		500425	SUDB: Company Program - Customer Connections*		$ 29,806,515	Sudbury & S.S Marie Customer Connections Program Items	Planned							
Northern	Div_43 - Sudbury & S.S. Marie	Utilization	Pass		48546	SUDB: Meter & Regulator Inst Repl-Company*	2020	$ 13,543,687	Meter & Reg Install- Replacement	Complete	Fail	See investment description, IRPAs not appliable					
Northern	Div_45 - Timmins	Distribution Pipe	Fail	Dollar threshold	48568	TIMM: Land Rights-Replacements	2023	$ 3,737									
Northern	Div_45 - Timmins	Distribution Pipe	Fail	Dollar threshold	48572	TIMM: Indirect Materials-Replacements	2023	$ 92,290									
Northern	Div_45 - Timmins	Distribution Pipe	Fail	Dollar threshold	100951	TIMM: Xstrata (Kidd Creek) Smelter SMS Service Retirement	2031	$ 1,260,898									
Northern	Div_45 - Timmins	Distribution Pipe	Fail	Dollar threshold	102490	TIMM: Anodes*	2020	$ 235,667									
Northern	Div_45 - Timmins	Distribution Pipe	Pass		30137	Bay St-Timmins-1561	2032	$ 5,199,604	Bay St. - Timmins - 1561 Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.	Planned							
Northern	Div_45 - Timmins	Distribution Pipe	Pass		30147	Hemlock St-Timmins-1569	2032	$ 2,827,018	Hemlock St. - Timmins - 1569 Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.	Planned							
Northern	Div_45 - Timmins	Distribution Pipe	Pass		30150	Maple St N-Timmins-1535	2028	$ 4,386,354	Maple St. N. - Timmins - 1535 Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.	Complete	Fail	NPS 2, cannot downsize or retire					
Northern	Div_45 - Timmins	Distribution Pipe	Pass		30159	Sixth Ave-Timmins-1566	2030	$ 4,355,346	Sixth Ave. - Timmins - 1566 Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.	Planned							
Northern	Div_45 - Timmins	Distribution Pipe	Pass		733717	NPS 6 Iroquois Falls Retrofit	2026	$ 4,038,813	Project-Specific: External Corrosion Direct Assessment (ECDA) to In-Line Inspection (ILI) Program, supporting refinement of pipeline risk profile. Associated 2027 Operations and Maintenance (O&M) spend for ILI. 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% Specified Minimum Yield Strength (SMYS). It includes installation costs for permanent 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 that are identified through the inspections.	Complete	Fail	See investment description, IRPAs not appliable					
Northern	Div_45 - Timmins	Distribution Pipe	Pass		733718	NPS 6 Kapuskasing Retrofit	2026	$ 4,038,813	Project-Specific: External Corrosion Direct Assessment (ECDA) to In-Line Inspection (ILI) Program, supporting refinement of pipeline risk profile. Associated 2027 Operations and Maintenance (O&M) spend for ILI. 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% Specified Minimum Yield Strength (SMYS). It includes installation costs for permanent 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 that are identified through the inspections.	Complete	Fail	See investment description, IRPAs not appliable					
Northern	Div_45 - Timmins	Distribution Pipe	Pass		733719	NPS 6 Cochrane Loop	2026	$ 4,038,813	Project-Specific: External Corrosion Direct Assessment (ECDA) to In-Line Inspection (ILI) Program, supporting refinement of pipeline risk profile. Associated 2026 Operations and Maintenance (O&M) spend for ILI. 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% Specified Minimum Yield Strength (SMYS). It includes installation costs for permanent 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 that are identified through the inspections.	Complete	Fail	See investment description, IRPAs not appliable					
Northern	Div_45 - Timmins	Distribution Stations	Fail	Dollar threshold	100922	TIMM: Swastika TBS, Station Rebuild	2027	$ 832,646									
Northern	Div_45 - Timmins	Distribution Stations	Fail	Dollar threshold	502086	TIMM: 45-23-700 2881 Hwy 655 TBS Low-Piping	2029	$ 683,161									
Northern	Div_45 - Timmins	Distribution Stations	Fail	Dollar threshold	502087	TIMM: 45-23-701 Porcupine Primary Low-Piping Modifications	2029	$ 683,161									
Northern	Div_45 - Timmins	Distribution Stations	Fail	Dollar threshold	502088	TIMM: 45-22-702 Kirkland Lake (Northland) Power SMS Rebuild	2025	$ 1,637,777									
Northern	Div_45 - Timmins	Distribution Stations	Fail	Dollar threshold	503742	TIMM: Glencore Concentrator SMS, Boiler Replacement	2024	$ 203,777									
Northern	Div_45 - Timmins	Distribution Stations	Fail	Dollar threshold	733768	TIMM: Glencore Mine SMS, Boiler Replacement	2024	$ 162,766									

* in the Investment Name indicates a program item. Program items are unique as they represent numerous projects grouped together and budgeted in advance. This results in forecast spend appearing larger than it would at the project level and it also impacts the in-service dates

Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
Northern	Div_45 - Timmins	Distribution Stations	Fail	Dollar threshold	733769	TIMM: South Porcupine/Crawford TBS, Boiler Replacement	2029	$ 341,580									
Northern	Div_45 - Timmins	Distribution Stations	Fail	Dollar threshold	733770	TIMM: Porcupine PCS, Boiler Replacement	2026	$ 241,096									
Northern	Div_45 - Timmins	Distribution Stations	Fail	Dollar threshold	733771	TIMM: Kirkland Lake TBS, Boiler Replacement	2026	$ 191,574									
Northern	Div_45 - Timmins	Distribution Stations	Fail	Dollar threshold	733773	TIMM: Cochrane TBS, Boiler Replacement	2027	$ 213,712									
Northern	Div_45 - Timmins	Distribution Stations	Fail	Dollar threshold	733864	TIMM: Matheson TBS, Boiler Replacement	2028	$ 145,875									
Northern	Div_45 - Timmins	Distribution Stations	Fail	Dollar threshold	733868	TIMM: Schumacher TBS, Boiler Replacement	2029	$ 151,662									
Northern	Div_45 - Timmins	Distribution Stations	Fail	Dollar threshold	733871	TIMM: Dalton TBS (Mcbride St S.), Station Rebuild and Boiler Replacement	2030	$ 1,061,062									
Northern	Div_45 - Timmins	Distribution Stations	Fail	Dollar threshold	733873	TIMM: Kapuskasing TBS, Boiler Replacement	2031	$ 699,639									
Northern	Div_45 - Timmins	Distribution Stations	Fail	Dollar threshold	733874	TIMM: Moneta TBS, Boiler Replacement	2032	$ 267,524									
Northern	Div_45 - Timmins	Distribution Stations	Fail	Dollar threshold	733877	TIMM: Hwy 655 TBS, Boiler Replacement	2031	$ 289,651									
Northern	Div_45 - Timmins	Distribution Stations	Fail	Dollar threshold	734572	TIMM: Malette Kraft SMS Retirement	2030	$ 53,861									
Northern	Div_45 - Timmins	Distribution Stations	Fail	Dollar threshold	734573	TIMM: Evergreen Greenhouse SMS Retirement	2023	$ 6,377									
Northern	Div_45 - Timmins	Distribution Stations	Fail	Dollar threshold	734574	TIMM: Hallnor Mine PRS Retirement	2030	$ 70,737									
Northern	Div_45 - Timmins	Distribution Stations	Fail	Dollar threshold	734576	TIMM: Munoro Mine SMS Retirement	2032	$ 47,530									
Northern	Div_45 - Timmins	Distribution Stations	Fail	Dollar threshold	734623	TIMM: Opasatika TBS Rebuild	2028	$ 825,705									
Northern	Div_45 - Timmins	Distribution Stations	Fail	Dollar threshold	734624	TIMM: Mattice TBS Rebuild	2028	$ 825,705									
Northern	Div_45 - Timmins	Distribution Stations	Fail	Dollar threshold	734625	TIMM: Val Gagne TBS Rebuild	2029	$ 819,793									
Northern	Div_45 - Timmins	Distribution Stations	Fail	Dollar threshold	734626	TIMM: Fauquier TBS Rebuild	2029	$ 819,793									
Northern	Div_45 - Timmins	Distribution Stations	Fail	Dollar threshold	734943	TIMM: Kirkland Lake CMS (Kenogami) - Long-Term Odorant Solution	2023	$ 498,212									
Northern	Div_45 - Timmins	Distribution Stations	Fail	Dollar threshold	735730	TIMM: Monteith CMS	2025	$ 1,291,450									
Northern	Div_45 - Timmins	Distribution Stations	Pass		100920	TIMM: Hearst TBS, Rebuild	2023	$ 2,241,955	Issue/Concern/Opportunity: According to a geological investigation completed on this station in 2021 it was determined that the existing facilities have undergone movements (frost heave, sinking, erosion) which have caused structural damages between the existing buildings and interconnecting pipeline facilities. The operations department also confirmed that heaving/ movements have been an ongoing issue at this station since it was rebuilt in 2004. There is a need to replace the station or remediate existing soil, due to extensive ground movement and assets. This site was constructed new in 2005 and experienced significant movement by 2008. The site has been reworked once already and now requires additional work. A cost analysis should be considered to compare reworking the existing site versus relocating the station. Assets: Station ID 41301001 Related Program: There are no related C55 investments.	Planned							
Northern	Div_45 - Timmins	Distribution Stations	Pass		101158	TIMM: 45-22-700 Goldcorp Dome Mine SMS, Rebuild	2023	$ 2,149,400	Issue/Concern/Opportunity: Station needs to be raised or relocated due to seasonal flooding. Mine site has been built up around the station and there is no place for Spring thaw and/or rainwater to run off. Justification: The most likely risk/scenario is above-grade frozen valves/assets. The worst-case scenario is the inability to isolate and/or shut down the station in an emergency (i.e., injury, fire, or explosion) due to frozen flood waters. Assets: Station ID 42199002 Related Investments: 735784 (the heater replacement for this station)	Planned							
Northern	Div_45 - Timmins	Distribution Stations	Pass		733880	TIMM: Tembec Spruce Falls SMS, Rebuild	2024	$ 1,922,427	Issue/Concern/Opportunity: Customer-driven station needs a rebuild. Assets: 41402004 Related Investments: Not applicable.	Planned							
Northern	Div_45 - Timmins	Distribution Stations	Pass		734628	TIMM: Smooth Rock Falls CMS, TBS, and DRS Relocations/Retirements	2025	$ 3,486,916	Issue/Concern/Opportunity/Justification: Project may include modifications to whole town system. The project includes building new Town Border Station (TBS) at TC Energy. The existing Customer Meter Station (CMS) will be removed and the old TBS will be repurposed as Distribution Regulation Station (DRS). Scope is to be further defined in the future. Assets: Station #41501002 (TBS), 41501005 (CMS), 41502002 (DRS) Related Program: Not applicable.	Planned							
Northern	Div_45 - Timmins	Distribution Stations	Pass		734941	TIMM: Iroquois Falls TBS, Station Rebuild	2028	$ 2,752,350	Issue/Concern/Opportunity: The current station is experiencing frost heave due to a large pressure cut and the soil conditions that is leading to pipe movement. The existing regulation building has moved as a result and a rebuild of all regulation is required to remediate the issues. The scope will include the demolition and removal old the Regulator building. The site will receivel new fencing, grading improvements, and a new Remoter Terminal Unit (RTU) building (currently mounted outside on side of boiler building). The station is experiecing odourant injection issues, related to the Co-Gen facility. Due to the reduction in load as a result of the Co-Gen customer no longer requiring natural gas, setting Odourization injection rates with the current equipment is difficult for all flow patterns. The existing Heating building does not have adequate containment in the event of a glycol leak and will be addressed as part of this project. When the piping is remediated due to the frost heave, the site will be reduced to include only one filter. Assets: 41701002 Related Investments: N/A	Planned							
Northern	Div_45 - Timmins	Growth	Pass		30525	SRP_North_Timmins_Hwy 655_Reinforcement_NPS6_850m_6895kPa	2024	$ 2,050,589	A reinforcement project is required to ensure EGI can meet station minimum inlets on the 6,895 kPa Maximum Operating Pressure (MOP) system under design winter conditions (with 4,000 kPa minimum from TC). Station 41902024 only requires SAP/field update (no project cost associated).	Planned							

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Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
Northern	**Div_45 - Timmins**	Growth	**Pass**		**100936**	TIMM: West Timmins System Reinforcement (McBride North and Shirley/Riverside Stations)	**2023**	$ 934,148	**Issue/Concern/Opportunity: Based on generic subsystem growth, as defined by Network Analysis at 0.74% annually for Timmins, a project will be required around 2032 as pressures along Majestic Drive go below minimum. To resolve this capacity issue, either the HWY 101 bottleneck at Shirley/Riverside Drive can be resolved, or the McBride North DRS can be rebuilt to accommodate a higher outlet pressure. However, the above conclusions/recommendations are based on the generic growth model. There is a relatively high probability that large commercial/industrial customers in the area of McBride North will be added to the system earlier than 2032, which would require that the above recommendations be acted upon as early as 2021. Depending on what loads are added, based on growth in this area of Timmins, Network Analysis will need to confirm at that time what the specific requirements are to accommodate the specific loads. Distribution Opimization Engineering (DOE) identified this as a System Reinforcement Plan (SRP) project (FBPSTN_2018_41903048). If these modifications are not made, this could result in a denial of system attachments (i.e., forgone revenue). The worst case scenario is that there is no additional capacity, and/or there is an incident during the winter months causing outage. Assets: Station ID 41903048 Related Program: This project might include modifications to the existing McBride North DRS (41903044), depending on the preferred solution to address the above issue/concern.**	Planned							
Northern	**Div_45 - Timmins**	Growth	**Pass**		**500426**	TIMM: Company Program - Customer Connections*		$ 3,823,693	**Timmins Customer Connections Program Items**	Planned							
Northern	**Div_45 - Timmins**	Growth	**Pass**		**502816**	TIMM 45-21-501 St Jean @ Shirley NPS4 Reinforcement - Timmins	**2023**	$ 62,428	**Issue/Concern/Opportunity: There is a bottleneck in the distribution system in west end of Timmins. Growth is limited in the area so reinforcement by way of removing bottlenecks is required. Assets: NPS PE 4 Related Program: Not applicable**	Planned							
Northern	**Div_45 - Timmins**	Growth	**Pass**		**502817**	TIMM 45-22-502 Shirley St @ Riverside Rd NPS4 Reinforcement - Timmins	**2023**	$ 113,255	**Issue/Concern/Opportunity: Bottlenecks in distribution system are contributing to restrictions on growth on the west side of Timmins. Distribution Optimization Engineering has indicated both pipeline and station reinforcement will be required to enhance the system. Assets: Riverside Rd NPS4 Reinforcement - Timmins Related Program: N/A**	Planned							
Northern	**Div_45 - Timmins**	Utilization	**Pass**		**48570**	TIMM: Meter & Regulator Inst Repl-Company*	**2020**	$ 4,283,545	**Meter & Reg Install- Replacement**	Complete	**Fail**	See investment description, IRPAs not appliable for CNG					
Northern	**Div_46 - North Bay & Orillia**	Distribution Pipe	**Fail**	Dollar threshold	**1273**	Marten River Retrofit		$ 996,424									
Northern	**Div_46 - North Bay & Orillia**	Distribution Pipe	**Fail**	Dollar threshold	**1274**	Sudbury Loop & Sudbury Sec 2b Retrofit		$ 934,148									
Northern	**Div_46 - North Bay & Orillia**	Distribution Pipe	**Fail**	Dollar threshold	**30200**	Colborne St W 1 - Northeast - 1682	**2030**	$ 1,380,559									
Northern	**Div_46 - North Bay & Orillia**	Distribution Pipe	**Fail**	Dollar threshold	**30201**	Colborne St W 2 - Northeast - 1683	**2030**	$ 1,626,152									
Northern	**Div_46 - North Bay & Orillia**	Distribution Pipe	**Fail**	Dollar threshold	**30205**	Farah Ave - Northeast - 1288	**2032**	$ 1,582,435									
Northern	**Div_46 - North Bay & Orillia**	Distribution Pipe	**Fail**	Dollar threshold	**30208**	Galt St 1 - Northeast - 1690	**2032**	$ 1,695,811									
Northern	**Div_46 - North Bay & Orillia**	Distribution Pipe	**Fail**	Dollar threshold	**30214**	Janet St 1 - Northeast - 1699	**2027**	$ 1,632,590									
Northern	**Div_46 - North Bay & Orillia**	Distribution Pipe	**Fail**	Dollar threshold	**30218**	King St W - Northeast - 1239	**2029**	$ 68,316									
Northern	**Div_46 - North Bay & Orillia**	Distribution Pipe	**Fail**	Dollar threshold	**30219**	Laforest Ave - Northeast - 1270	**2029**	$ 1,341,662									
Northern	**Div_46 - North Bay & Orillia**	Distribution Pipe	**Fail**	Dollar threshold	**30221**	Maher St 2 - Northeast - 1703	**2032**	$ 1,074,810									
Northern	**Div_46 - North Bay & Orillia**	Distribution Pipe	**Fail**	Dollar threshold	**30224**	Matchedash St N 1 - Northeast - 1719	**2032**	$ 603,295									
Northern	**Div_46 - North Bay & Orillia**	Distribution Pipe	**Fail**	Dollar threshold	**30225**	Matchedash St N 2 - Northeast - 1720	**2032**	$ 325,217									
Northern	**Div_46 - North Bay & Orillia**	Distribution Pipe	**Fail**	Dollar threshold	**30230**	Princess St W 1 - Northeast - 1721	**2032**	$ 1,099,801									
Northern	**Div_46 - North Bay & Orillia**	Distribution Pipe	**Fail**	Dollar threshold	**30232**	Tanguay Ave - Northeast - 1280	**2029**	$ 866,205									
Northern	**Div_46 - North Bay & Orillia**	Distribution Pipe	**Fail**	Dollar threshold	**48575**	NE: Dist-Repl-Contr-Mains Leakage*	**2020**	$ 4,056,177									
Northern	**Div_46 - North Bay & Orillia**	Distribution Pipe	**Fail**	Dollar threshold	**48580**	NE: Dist-Repl-Contr-Mains Municipal*	**2020**	$ 9,933,819									
Northern	**Div_46 - North Bay & Orillia**	Distribution Pipe	**Fail**	Dollar threshold	**48584**	NBAY: Land Rights-Replacements	**2023**	$ 6,228									
Northern	**Div_46 - North Bay & Orillia**	Distribution Pipe	**Fail**	Dollar threshold	**48588**	NBAY: Misc Materials-Company	**2023**	$ 6,228									
Northern	**Div_46 - North Bay & Orillia**	Distribution Pipe	**Fail**	Dollar threshold	**49621**	NBAY: 128 McIntyre St W, North Bay	**2023**	$ 42,348									
Northern	**Div_46 - North Bay & Orillia**	Distribution Pipe	**Fail**	Dollar threshold	**49623**	NBAY: 955 McKeown Ave, North Bay	**2025**	$ 96,859									
Northern	**Div_46 - North Bay & Orillia**	Distribution Pipe	**Fail**	Dollar threshold	**49624**	NBAY: 198 Hughes Rd, North Bay	**2026**	$ 32,581									
Northern	**Div_46 - North Bay & Orillia**	Distribution Pipe	**Fail**	Dollar threshold	**49625**	NBAY: 247 Whitewood Ave, New Liskeard Main Relocation	**2031**	$ 209,892									
Northern	**Div_46 - North Bay & Orillia**	Distribution Pipe	**Fail**	Dollar threshold	**49627**	New Liskeard Mall, New Liskeard	**2023**	$ 79,048									
Northern	**Div_46 - North Bay & Orillia**	Distribution Pipe	**Fail**	Dollar threshold	**49638**	NBAY: 205 Main St E, North Bay	**2023**	$ 80,959									
Northern	**Div_46 - North Bay & Orillia**	Distribution Pipe	**Fail**	Dollar threshold	**49644**	NBAY: 300 Lakeshore Dr, North Bay	**2023**	$ 112,098									
Northern	**Div_46 - North Bay & Orillia**	Distribution Pipe	**Fail**	Dollar threshold	**49649**	Giroux St Dent Repair, Sudbury	**2027**	$ 104,081									
Northern	**Div_46 - North Bay & Orillia**	Distribution Pipe	**Fail**	Dollar threshold	**102476**	NE: Ski Club Rd., North Bay	**2029**	$ 510,001									
Northern	**Div_46 - North Bay & Orillia**	Distribution Pipe	**Fail**	Dollar threshold	**501007**	NBAY: PSLL Maintenance	**2023**	$ 196,943									
Northern	**Div_46 - North Bay & Orillia**	Distribution Pipe	**Fail**	Dollar threshold	**735150**	NE: Hwy 11 and Barnett, North Bay, Grasshopper Valves Replacement	**2028**	$ 584,874									

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Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
Northern	**Div_46 - North Bay & Orillia**	Distribution Pipe	**Pass**		**30197**	4th Ave E - Northeast - 1302	**2031**	$ 1,887,402	**4th Ave. E. - Northeast - 1302** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: There is rocky terrain.**	Planned							
Northern	**Div_46 - North Bay & Orillia**	Distribution Pipe	**Pass**		**30198**	Alder St 1 - Northeast - 1715	**2031**	$ 2,122,240	**Alder St. 1 (moratorium until 2026) - Northeast - 1715** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: Project will take 11 months / 2 years to complete. Project was updated based on regional feedback (Alder St. 1 – 1715 and Alder St. 2 - 1716). It is rocky and rectifier is in area. Road work was just completed on Beatty St. Project was updated to reflect a moratorium until 2026.**	Planned							
Northern	**Div_46 - North Bay & Orillia**	Distribution Pipe	**Pass**		**30199**	Alder St 2 - Northeast - 1716	**2032**	$ 2,045,448	**Alder St. 2 (moratorium until 2026) - Northeast - 1716** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: Project will take 11 months / 2 years to complete. Project was updated based on regional feedback (Alder St. 1 – 1715 and Alder St. 2 - 1716). It is rocky and there is a rectifier in the area.** **Road work was just completed on Beatty St. Project was updated to reflect a moratorium until 2026.**	Planned							
Northern	**Div_46 - North Bay & Orillia**	Distribution Pipe	**Pass**		**30206**	Ferguson Ave 1 - Northeast - 1686	**2032**	$ 2,208,807	**Ferguson Ave. 1 - Northeast - 1686** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: Project will take 16 months / 2.5 years to complete. Project was updated based on regional feedback (Ferguson Ave. 1 - 1686, Ferguson Ave. 2 - 1688). Permit may be required.**	Planned							
Northern	**Div_46 - North Bay & Orillia**	Distribution Pipe	**Pass**		**30207**	Ferguson Ave 2 - Northeast - 1688	**2030**	$ 2,470,442	**Ferguson Ave. 2 - Northeast - 1688** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: It will take 16 months / 2.5 years to complete. Project was updated based on regional feedback (Ferguson Ave. 1 - 1686 and Ferguson Ave. 2 - 1688). Permit may be required.**	Planned							
Northern	**Div_46 - North Bay & Orillia**	Distribution Pipe	**Pass**		**30209**	Galt St 2 - Northeast - 1691	**2029**	$ 2,101,362	**Galt St. 2 - Northeast - 1691** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: Project will take 12 months / 2 years to complete. Project was updated based on regional feedback (Galt St. 1 - 1690, Galt St. 1 - 1690).**	Planned							
Northern	**Div_46 - North Bay & Orillia**	Distribution Pipe	**Pass**		**30211**	Georgina Ave 2 - Northeast - 1695	**2028**	$ 2,009,206	**Georgina Ave. 2 - Northeast - 1695** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: Project will take 16 months / 2.5 years to complete. Project was updated based on regional feedback (Georgina Ave. 1 - 1686, Ferguson Ave. 2 - 1688). Permit may be required.**	Planned							
Northern	**Div_46 - North Bay & Orillia**	Distribution Pipe	**Pass**		**30212**	Hilda St 1 - Northeast - 1696	**2031**	$ 2,386,808	**Hilda St. 1 - Northeast - 1696** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: It will take 14 months / 2 years to complete. Project was updated based on region (Hilda St. 1 - 1696 and Hilda St. 2 - 1698).**	Planned							

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Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
Northern	Div_46 - North Bay & Orillia	Distribution Pipe	Pass		30213	Hilda St 2 - Northeast - 1698	2028	$ 2,151,905	Hilda St. 2 - Northeast - 1698 Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization. Comments: Project will take 14 months / 2 years to complete. Project was updated based on region (Hilda St. 1 - 1696, Hilda St. 2 - 1698).	Planned							
Northern	Div_46 - North Bay & Orillia	Distribution Pipe	Pass		30215	Janet St 2 - Northeast - 1700	2030	$ 1,869,816	Janet St. 2 - Northeast - 1700 Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization. Comments: Project will take 13 months / 2 years to complete. Project was updated based on regional feedback (Janet St. 1 - 1699 and Janet St. 2 - 1700). There is rocky terrain.	Planned							
Northern	Div_46 - North Bay & Orillia	Distribution Pipe	Pass		30220	Maher St 1 - Northeast - 1701	2030	$ 2,065,519	Maher St. 1 - Northeast - 1701 Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization. Comments: Project is 8 months of work which is difficult to fit into one year. Project was updated based on regional feedback (Maher St. 1 - 1701, Maher St. 2 - 1703). Permit may be required.	Planned							
Northern	Div_46 - North Bay & Orillia	Distribution Pipe	Pass		30222	Mary St 1 - Northeast - 1708	2029	$ 2,228,996	Mary St. 1 - Northeast - 1708 Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization. Comments: Project will take 12 months / 2 years to complete. Project was updated based on regional feedback (Mary St. 1 - 1708 and Mary St. 2 - 1709).	Planned							
Northern	Div_46 - North Bay & Orillia	Distribution Pipe	Pass		30228	Presley St 1 - Northeast - 1713	2031	$ 3,227,918	Presley St. 1 - Northeast - 1713 Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization. Comments: It will take 17 months / 2.5 years to complete. It is a tight area to work in. The project was updated based on regional feedback (Presley St. 1 - 1713 and Presley St. 2 – 1714). Permit may be required.	Planned							
Northern	Div_46 - North Bay & Orillia	Distribution Pipe	Pass		30229	Presley St 2 - Northeast - 1714	2031	$ 2,224,956	Presley St. 2 - Northeast - 1714 Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization. Comments: Project will take 17 months / 2.5 years to complete. There is a tight area to work in. Project was updated based on regional feedback (Presley St. 1 - 1713, Presley St. 2 - 1714). Permit may be required.	Planned							
Northern	Div_46 - North Bay & Orillia	Distribution Pipe	Pass		30233	Wickstead Ave - Northeast - 1510	2032	$ 3,326,557	Wickstead Ave. (moratorium until 2026) - Northeast - 1510 Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization. Comments: Water and sewer were just redone on Lavase at the middle of polygon. Also, from Mountainview to Lavase on Mountainview, water and sewer were done in 2021. The road will not be able to be cut in these sections. This project was updated to reflect a moratorium until 2026.	Planned							
Northern	Div_46 - North Bay & Orillia	Distribution Pipe	Pass		48590	NBAY: Anodes*	2020	$ 8,308,340	General: The anodes program within the corrosion program includes the required expenditure to install anodes in order to reduce the amount of down plant within EGI's 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.	Complete	Fail	See investment description, IRPAs not appliable					
Northern	Div_46 - North Bay & Orillia	Distribution Stations	Fail	Dollar threshold	48577	NBAY: Plan(T)-Dist-Stn Measuring/Corrosion Stn*	2019	$ 268,022									
Northern	Div_46 - North Bay & Orillia	Distribution Stations	Fail	Dollar threshold	502662	NE: 42801004 - Cobalt TBS, Rebuild	2025	$ 710,298									
Northern	Div_46 - North Bay & Orillia	Distribution Stations	Fail	Dollar threshold	502663	NE: 44702001 - Rutherglen TBS, Rebuild	2028	$ 688,087									
Northern	Div_46 - North Bay & Orillia	Distribution Stations	Fail	Dollar threshold	502704	NE: 43601001 - Balls Dr TBS, Rebuild	2028	$ 1,307,366									
Northern	Div_46 - North Bay & Orillia	Distribution Stations	Fail	Dollar threshold	503273	NE PFM Compliance Program*		$ 411,651									
Northern	Div_46 - North Bay & Orillia	Distribution Stations	Fail	Dollar threshold	733366	NE: 44602002 - Burks Falls TBS, Station Rebuild	2023	$ 809,595									
Northern	Div_46 - North Bay & Orillia	Distribution Stations	Fail	Dollar threshold	733757	NBAY: Muskoka Falls TBS, Boiler Replacement	2024	$ 208,904									

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Northern	Div_46 - North Bay & Orillia	Distribution Stations	Fail	Dollar threshold	733758	NBAY: Ski Club/Trout Lake TBS, Boiler Replacement	2024	$ 320,405									
Northern	Div_46 - North Bay & Orillia	Distribution Stations	Fail	Dollar threshold	733759	NBAY: Haileybury TBS, Boiler Replacement	2025	$ 220,838									
Northern	Div_46 - North Bay & Orillia	Distribution Stations	Fail	Dollar threshold	733760	NBAY: Sturgeon Falls TBS, Boiler Replacement	2025	$ 180,803									
Northern	Div_46 - North Bay & Orillia	Distribution Stations	Fail	Dollar threshold	733761	NBAY: Englehart TBS, Boiler Replacement	2025	$ 180,803									
Northern	Div_46 - North Bay & Orillia	Distribution Stations	Fail	Dollar threshold	733764	NBAY: Eloy TBS, Boiler Replacement	2026	$ 325,806									
Northern	Div_46 - North Bay & Orillia	Distribution Stations	Fail	Dollar threshold	733766	NBAY: West St TBS, Boiler Replacement	2027	$ 326,120									
Northern	Div_46 - North Bay & Orillia	Distribution Stations	Fail	Dollar threshold	733795	NBAY: Widdifield TBS, Boiler Replacement	2028	$ 145,875									
Northern	Div_46 - North Bay & Orillia	Distribution Stations	Fail	Dollar threshold	733796	NBAY: Mattawa TBS, Boiler Replacement	2028	$ 145,875									
Northern	Div_46 - North Bay & Orillia	Distribution Stations	Fail	Dollar threshold	733797	NBAY: South River TBS, Boiler Replacement	2028	$ 145,875									
Northern	Div_46 - North Bay & Orillia	Distribution Stations	Fail	Dollar threshold	733820	NBAY: Ferguson Road, Boiler Replacement	2029	$ 151,662									
Northern	Div_46 - North Bay & Orillia	Distribution Stations	Fail	Dollar threshold	733821	NBAY: New Liskeard TBS, Boiler Replacement	2029	$ 232,275									
Northern	Div_46 - North Bay & Orillia	Distribution Stations	Fail	Dollar threshold	733822	NBAY: Earlton TBS, Boiler Replacement	2029	$ 151,662									
Northern	Div_46 - North Bay & Orillia	Distribution Stations	Fail	Dollar threshold	733823	NBAY: Ravensglen TBS, Boiler Replacement	2029	$ 341,580									
Northern	Div_46 - North Bay & Orillia	Distribution Stations	Fail	Dollar threshold	733838	NBAY: West Ferris TBS, Boiler Replacement	2030	$ 165,526									
Northern	Div_46 - North Bay & Orillia	Distribution Stations	Fail	Dollar threshold	733839	NBAY: TCPL Co-gen North Bay, Boiler Replacement	2030	$ 253,240									
Northern	Div_46 - North Bay & Orillia	Distribution Stations	Fail	Dollar threshold	733840	NBAY: Madill TBS _ Huntsville, Boiler Replacement	2030	$ 253,240									
Northern	Div_46 - North Bay & Orillia	Distribution Stations	Fail	Dollar threshold	733842	NBAY: Callander TBS, Boiler Replacement	2031	$ 172,111									
Northern	Div_46 - North Bay & Orillia	Distribution Stations	Fail	Dollar threshold	733851	NBAY: Emsdale CMS, Boiler Replacement	2031	$ 172,111									
Northern	Div_46 - North Bay & Orillia	Distribution Stations	Fail	Dollar threshold	734577	NE: 43801032 - Stepan Industries, Station Retirement	2026	$ 78,193									
Northern	Div_46 - North Bay & Orillia	Distribution Stations	Fail	Dollar threshold	734578	NE: 43801017 - Huronia regional Centre, Station Retirement	2025	$ 64,573									
Northern	Div_46 - North Bay & Orillia	Distribution Stations	Fail	Dollar threshold	734579	NE: 43804002 - Occupational Centre PRS, Station Retirement	2027	$ 27,755									
Northern	Div_46 - North Bay & Orillia	Distribution Stations	Fail	Dollar threshold	734580	NE: 43101005 - Sturgeon Falls Mill SMS, Station Retirement	2024	$ 76,897									
Northern	Div_46 - North Bay & Orillia	Distribution Stations	Fail	Dollar threshold	735030	NBAY: Warren TBS, Boiler Replacement	2030	$ 165,526									
Northern	Div_46 - North Bay & Orillia	Distribution Stations	Pass		101073	NE: 42601002 - Englehart TBS, Relocation	2025	$ 2,187,108	**Issue/Concern/Opportunity: There is 1.5 km of unodourized gas from TC Energy pipeline to inlet of the existing TBS. The NPS2 transmission inlet line to the station has unodourized gas that could go undetected in the event of a leak due to the properties (colourless and odourless) of natural gas. Odourant is added within the station compound. However, the Odourant system is installed at the TBS which is in a populated area. The station requires relocation.** **Note, that the station bypass valve is also leaking on the unodourized side.** **A rebuild of the station and possible relocation to ensure that the natural gas is odourized appropriately.** **Justification: Station feeds town of Englehart and large customer Columbia Forest Products.** **Assets: Station 42601002** **Related Investments: Not applicable.**	Planned							
Northern	Div_46 - North Bay & Orillia	Growth	Pass		48574	NBAY: Company Program - New Business - Scattered Mains - Contractor*	2020	$ 11,650,069	**Scattered Mains**	Planned							
Northern	Div_46 - North Bay & Orillia	Growth	Pass		49164	NBAY: Upgrade Maplewood PRS (43801127)	2023	$ 5,739	**Issue/Concern/Opportunity: Station has growth concerns that were identified by Distribution Optimization Engineering. Station was over capacity in 2021 and will continue to be put further over capacity due to the growth. Station will require modifications to the regulators and reliefs to meet capacity concerns.** **The station has capacity concerns which could result in operational issues in the future. The station services approximately 650 customers and is not backfed.** **Assets: 43801127** **Related Investments: Not applicable.**	Planned							
Northern	Div_46 - North Bay & Orillia	Growth	Pass		500427	NBAY: Company Program - Customer Connections*		$ 48,587,762	**North Bay Customer Connections Program Items**	Planned							
Northern	Div_46 - North Bay & Orillia	Utilization	Pass		48586	NBAY: Meter & Regulator Inst Repl-Company*	2020	$ 8,084,506	**Meter & Reg Install- Replacement**	Complete	Fail	See investment description, IRPAs not appliable					
Southeast	80 - Niagara	Distribution Pipe	Fail	Dollar threshold	14063	Copper Service Replacement - Area 80*	2020	$ 1,291,892									
Southeast	80 - Niagara	Distribution Pipe	Fail	Dollar threshold	30048	Burleigh Hill Dr STC - Area 80 - 1131	2028	$ 1,757,829									
Southeast	80 - Niagara	Distribution Pipe	Fail	Dollar threshold	30052	Erie St STC - Area 80 - 1159	2029	$ 1,619,621									
Southeast	80 - Niagara	Distribution Pipe	Fail	Dollar threshold	30053	Food City Plaza STC - Area 80 - 1161	2032	$ 641,325									
Southeast	80 - Niagara	Distribution Pipe	Fail	Dollar threshold	30063	Lockhart St NOTL - Area 80 - 1189	2031	$ 1,188,270									
Southeast	80 - Niagara	Distribution Pipe	Fail	Dollar threshold	30065	Neff St PTC - Area 80 - 1165	2030	$ 1,353,298									
Southeast	80 - Niagara	Distribution Pipe	Fail	Dollar threshold	30074	Rose St STC - Area 80 - 1134	2028	$ 686,333									
Southeast	80 - Niagara	Distribution Pipe	Fail	Dollar threshold	30076	Shurie Rd LINC - Area 80 - 1154	2028	$ 765,232									
Southeast	80 - Niagara	Distribution Pipe	Fail	Dollar threshold	30077	Summer St NFalls- Area 80 - 1137	2029	$ 1,527,127									
Southeast	80 - Niagara	Distribution Pipe	Fail	Dollar threshold	30079	Victoria St STC- Area 80 - 1148	2027	$ 979,580									
Southeast	80 - Niagara	Distribution Pipe	Fail	Dollar threshold	30080	Welland St PTC- Area 80 - 1173	2027	$ 1,039,606									
Southeast	80 - Niagara	Distribution Pipe	Fail	Dollar threshold	102425	Relocation Program - Area 80*	2020	$ 13,424,702									
Southeast	80 - Niagara	Distribution Pipe	Fail	Dollar threshold	103520	Red Maple Dr Lincoln - 1-inch steel main replacement	2028	$ 392,355									
Southeast	80 - Niagara	Distribution Pipe	Fail	Dollar threshold	502017	Ridge Rd North Fort Erie	2025	$ 1,190,916									
Southeast	80 - Niagara	Distribution Pipe	Fail	Dollar threshold	502019	Regional Rd 65 West Lincoln	2025	$ 216,721									
Southeast	80 - Niagara	Distribution Pipe	Fail	Dollar threshold	503325	Lundys Lane Reg. Road 20 Niagara Falls	2025	$ 625,200									
Southeast	80 - Niagara	Distribution Pipe	Fail	Emergent Safety	4666	Replacement Blanket - Area 80*		$ 2,013,705									

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Southeast	**80 - Niagara**	Distribution Pipe	**Pass**		**1938**	NPS 10 Glenridge Avenue, St. Catharines	**2026**	$ 15,332,118	**Issue/Concern:** **General Concerns: Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (Vintage Steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Site-Specific Concerns: This project looks to replace approximately 8.7 km 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.** **A 2019 Depth of Cover (DOC) survey found that 366 (33%) survey locations had less than 90 cm of cover, and 90 survey locations (8%) had DOC<60 cm, 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 (CC) 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 CCs 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.**	Planned							
Southeast	**80 - Niagara**	Distribution Pipe	**Pass**		**4673**	Anode Blanket - Area 80*	**2020**	$ 3,190,809	**General Description: The anodes program within the corrosion program includes the required expenditure to install anodes in order to reduce the amount of down plant within the EGI system. These installations and replacements are based on the Corrosion Operating Standard established to maintain the appropriate level of cathodic protection on steel pipeline assets.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Southeast	**80 - Niagara**	Distribution Pipe	**Pass**		**4768**	AMP Fitting Replacement - Area 80*		$ 40,070,557	**AMP Fittings are a below grade transition fittings. The inserted portion of copper tubing can fail due to internal corrosion. In these cases leaks develop immediately downstream of the AMP Fitting.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Southeast	**80 - Niagara**	Distribution Pipe	**Pass**		**8258**	Woodington Rd NFalls 1" ST Repalcement	**2023**	$ 1,980,451	**Issue/Concern: 1-inch Steel and Copper Risers** **Replace existing 3,302 m of existing steel main and 151 services in area defined.**	Planned							
Southeast	**80 - Niagara**	Distribution Pipe	**Pass**		**13611**	Service Relay Blanket - Area 80*	**2020**	$ 24,369,554	**General: 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.**	Planned							
Southeast	**80 - Niagara**	Distribution Pipe	**Pass**		**23230**	Black Creek Rd and River Trail, Fort Erie - VPM Aldyl-A MP lined in steel	**2023**	$ 1,706,660	**Issue/Concern: General: 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 Rd and River Trail, Fort Erie - VPM Aldyl-A MP lined in steel** **Black Creek - Phase One - Scope: consists of 1001M, NPS 4 PE Intermediate Pressure (IP), 13 Medium Pressure (MP) to IP Services and one water crossing (drainage ditch). A Header at 13693 Niagara River Parkway also will be replaced as part of this phase: 230M NPS 2 PE IP and 4 MP to PI Services.** **Status as of 1/21/2021: Survey has been completed for both the Main Replacement as well as the Header Replacement. Drawing completed for the Main Replacement portion of the project and class 3 estimate has been submitted and completed by Construction, C55 numbers to be updated once Class 3 for Phase 2 is completed. Submitted to Land for preliminary Species at Risk (SAR) and permits review. Early consultation with Land shows existing valid easement at Header location. MTO permit will not be required. Follow up requested from Land 1/21/2021 and copy of DWG provided. Header DWG in progress – estimate was included with Phase 1 and is complete.** **Black Creek - Phase Two - Scope: consists of 3230M NPS 4 PE IP, 214M NPS 2 PE IP, the replacement of 17 IP to IP services and 34 MP to IP services. There are two Headers that will be replaced as part of this phase. 1) Private Laneway: 253M, NPS 2 PE IP and 2 MP to IP Services. 2) Switch Road: 363M NPS 2 PE IP and 3 MP to IP Services. Project also has one water crossing and 3 Concrete Culvert**	Planned							
Southeast	**80 - Niagara**	Distribution Pipe	**Pass**		**30046**	2nd Ave PTC - Area 80 - 1180	**2032**	$ 4,468,978	**2nd Ave. - Area 80 - 1180** **Vintage steel exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: Plan Year 1 and Execute Year 2 (1711990).**	Planned							
Southeast	**80 - Niagara**	Distribution Pipe	**Pass**		**30047**	Briarsdale Dr STC - Area 80 - 1174	**2032**	$ 3,014,798	**Briarsdale Dr. - Area 80 - 1174** **Vintage steel pipes exhibit increased failures as they age, as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization** **Comments: Plan Year 1 and execute Year 2.**	Complete	**Fail**	NPS 2, cannot downsize or retire					
Southeast	**80 - Niagara**	Distribution Pipe	**Pass**		**30049**	Cattell Dr NFalls- Area 80 - 1170	**2032**	$ 2,638,617	**Cattell Dr. - Area 80 - 1170** **Vintage steel pipes exhibit increased failures as they age, as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization**	Planned							

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Southeast	**80 - Niagara**	Distribution Pipe	**Pass**		**30050**	Dexter Dr WELL - Area 80 - 1169	**2030**	$ 3,715,274	**Dexter Dr. - Area 80 - 1169** **Vintage steel pipes exhibit increased failures as they age, as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: Plan Year 1 and execute Year 2.**	Planned							
Southeast	**80 - Niagara**	Distribution Pipe	**Pass**		**30054**	Forkes Rd E PTC - Area 80 - 1132	**2031**	$ 3,308,747	**Forkes Rd. E. - Area 80 - 1132** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: Plan Year 1 and execute Year 2.**	Planned							
Southeast	**80 - Niagara**	Distribution Pipe	**Pass**		**30055**	Geneva St STC - Area 80 - 1187	**2031**	$ 7,869,856	**Geneva Street - Area 80 – 1187** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: Plan Year 1 and execute Year 2.**	Planned							
Southeast	**80 - Niagara**	Distribution Pipe	**Pass**		**30056**	Flanders Ave STC - Area 80 - 1809	**2030**	$ 4,664,378	**Handers Ave. - Area 80 - 1156** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: Plan Year 1 and execute Year 2.**	Planned							
Southeast	**80 - Niagara**	Distribution Pipe	**Pass**		**30057**	Hillcrest Ave STC - Area 80 - 1176	**2028**	$ 1,984,698	**Hillcrest Ave. - Area 80 - 1176** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
Southeast	**80 - Niagara**	Distribution Pipe	**Pass**		**30058**	Hixon St LINC - Area 80 - 1153	**2032**	$ 2,040,131	**Hixon St. - Area 80 - 1153** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
Southeast	**80 - Niagara**	Distribution Pipe	**Pass**		**30062**	Lavinia St FE - Area 80 - 1171	**2029**	$ 2,847,536	**Lavinia St. - Area 80 - 1171** **Vintage steel pipes exhibit increased failures as they age, as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: Plan Year 1 and execute Year 2.**	Planned							
Southeast	**80 - Niagara**	Distribution Pipe	**Pass**		**30064**	McCain St PTC - Area 80 - 1136	**2031**	$ 2,321,259	**McCain St. - Area 80 - 1136** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: Plan Year 1 and execute Year 2.**	Planned							
Southeast	**80 - Niagara**	Distribution Pipe	**Pass**		**30067**	Niagara Wine Route 2 NOTL- Area 80 - 1191	**2030**	$ 1,938,422	**Niagara Wine Route 2 - Area 80 - 1191** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: Plan Year 1 and execute Year 2**	Planned							

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Southeast	**80 - Niagara**	Distribution Pipe	**Pass**		**30071**	Queen St LINC - Area 80 - 1150	**2029**	$ 2,241,560	**Queen St. - Area 80 - 1150** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Complete	**Fail**	NPS 2, cannot downsize or retire					
Southeast	**80 - Niagara**	Distribution Pipe	**Pass**		**30078**	Swan Dr STC- Area 80 - 1163	**2032**	$ 4,517,357	**Swan Dr. - Area 80 - 1163** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: Plan Year 1 and execute Year 2.**	Planned							
Southeast	**80 - Niagara**	Distribution Stations	**Fail**	Dollar threshold	**7759**	THOROLD TOWNLINE GATE	**2024**	$ 888,490									
Southeast	**80 - Niagara**	Distribution Stations	**Fail**	Dollar threshold	**7760**	VINELAND GATE	**2026**	$ 875,031									
Southeast	**80 - Niagara**	Distribution Stations	**Fail**	Dollar threshold	**18850**	GRASSYBROOK & MCKENNY DISTRICT	**2026**	$ 157,496									
Southeast	**80 - Niagara**	Distribution Stations	**Fail**	Dollar threshold	**18851**	ONTARIO & DEERE DISTRICT LP	**2026**	$ 283,358									
Southeast	**80 - Niagara**	Distribution Stations	**Fail**	Dollar threshold	**18917**	TOWNLINE & RUSHOLME DISTRICT	**2023**	$ 144,018									
Southeast	**80 - Niagara**	Distribution Stations	**Pass**		**3610**	CROWLAND STORAGE TRANSFER	**2023**	$ 24,124,880	**Crowland Storage Transfer Station is located on EGI-owned property of approximately 7,300 m2 fenced compound in the Port Colborne, Ontario, approximately 7 km southeast of Welland, Ontario, within a rural area, in close proximity to a railway corridor. This station accepts natural gas from EGI Crowland Gas Storage facilities and provides supply to and from XHP networks, through components within the measurement system, pressure control system , heating system, odourant system, and telemetry system. This station delivers and withdraws natural gas from Storage Operations Wells in the Niagara Region. The following issues have been identified at this station:** **Odourization: The odourant system was installed in 2000. The current configuration of the odourant system does not ensure adequate containment of the odourant product in the event of a leak and does not meet the current engineering standards and approvals.** **Telemetry & Electrical: The existing electrical system does not meet current EGI electrical installation standards. This poses a potential electrical hazard and faulty wiring may result in lost communications.** **Compliance: The Canadian Electrical Code Section 22.1 indicates that all electrical and instrumentation equipment located in a hazardous area must be rated for that area classification. The Remoter Terminal Unit (RTU) building has been identified as being located in an area classification and its equipment is not rated to operate in this environment. This is a risk of ignition and fire in the event of a gas leak.** **Scope Includes:** **1) Install annubars on inlet and outlet.** **-Install actuator on each operator regulator and on valves 8, 9 and 10.** **Required electrical work:** **-Relocate RTU building out of classified area (including new building and foundation).** **-Install generator and automatic transfer switch.** **-Upgrade tower to improve signal quality.** **-Upgrade lighting.** **2) Install filter separator and receiver on inlet.**	Planned							
Southeast	**80 - Niagara**	Distribution Stations	**Pass**		**3620**	MOUNTAIN RD GATE	**2026**	$ 4,651,715	**Mountain Road Gate Station is located on EGI-owned property of approximately 1,800 m2 in a fenced compound in Niagara Falls, Ontario, approximately 10 km from Niagara Falls, within a rural/urban area. This station accepts natural gas from TC Energy and provides supply to one NPS 12 XHP network (Glendale), one NPS 12 HP network (Dorchester), and one NPS 8 IP network (Lundy's Lane). The gate station includes a measurement system, pressure control system, heating system, odourant system, and telemetry system. This station supplies natural gas to approximately 85,700 customers in the Niagara region. The following issues have been identified at this station:** **Valves & Piping: Valve actuators have been installed on the outlet valves and on the heat exchanger isolation and bypass valves, but programming is required to control the actuators with the Remote Terminal Unit (RTU). Valves are functioning well but are all original valves that were installed during the installation of the gate station (approximately 30 years) and may need to be replaced due to age.** **Measurement: The inlet is metered by a relatively new NPS 12 ultrasonic meter (approximately 10 years). The current system does not provide measurement of the individual outlet supplies. Visibility to each outlet supply provides greater redundancy to the existing measurement and improved response capabilities. Outlet metering is to be connected to SCADA and visible to the Gas Control group.** **Heating: Three existing boilers at this site are old boilers that are approximately 20 years old. They have had 10 trouble call/failures over the recent years, including failures of the motors and pumps, burner lock-outs and exchanger failures. The existing heat exchanger was installed in 1995 and will be at end of life by the rebuild date. Due to recent and upcoming customer growth in the Niagara Falls area, the existing heating system will not be capable of supplying the heating requirements to meet the demand. Fuel gas station to the boilers is metered but conversion of the generator from diesel to natural gas will require it to be upsized.** **Pressure Control: The configuration of the existing regulators are all boot-style regulators, posing an undesired higher risk and high associated ongoing maintenance costs. The regulators will have to be replaced. In addition, an upstream filter should be installed.** **Odourization: The odourant injection system is a combination of Link and Wilroy pumps which are located in a separate building**	Planned							
Southeast	**80 - Niagara**	Distribution Stations	**Pass**		**7752**	NIAGARA GATE	**2024**	$ 4,550,640	**Niagara Gate Station is located on EGI-owned property of approximately 1,900 m2 fenced compound in the Town of Niagara-on-the-Lake , Ontario, approximately 7 km from Niagara-on-the-Lake, ON, within a rural area. This station accepts natural gas from TC Energy and provides supply to an XHP network, through components within the Measurement system, Pressure Control system, Heating system, Odourant system, and Telemetry system. This station supplies natural gas to approximately 6,800 customers in the Niagara Region. The following issues have been identified at this station:** **Heating: The existing boilers at this site are 15 years old, they have had numerous trouble call/failures recently, including failures of the motors and pumps, burner lock-outs and exchanger failures, and are at end of life. Repairs have been made but the reliability of the heating system is no longer acceptable. The proposal is to replace the existing boiler system with a CWT outside of any hazardous area.** **Telemetry & Electrical: The existing Electrical system does not meet current EGI electrical installation standards. This poses a potential electrical hazard and faulty wiring may result in lost communications. A new natural gas generator for backup power will also be required.**	Planned							

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Southeast	**80 - Niagara**	Distribution Stations	**Pass**		**16586**	TALISMAN PRODUCTION	**2025**	$ 1,916,321	**Issue/Concern:** **Measurement: Currently, a Turbine meter is used with no problems.** **Assets: Odourant, Telemetry, Related Program (if applicable).** **Measurement: There is flanged obsolete Daniel Senior orifice meter on site on the outlet piping that needs to be removed; a simple flanged spool piece can be inserted.** **Odourant: Old odourant pumps and a separate odourant tank need to be put into a single building with containment.** **Telemetry and Electrical: Currently, old Remote Terminal Unit (RTU) 3330 is required to be upgraded. The Telemetry and Electrical systems do not meet current EGI standards, do not contain backup power supply in the event of power loss, and are approaching end of useful life. The existing RTU is obsolete and is required to be upgraded to current standards along with new communications equipment in order to eliminate cybersecurity threats. There should be an upgrade of RTU to Control Wave Micro. There should be an upgrade of electrical wiring to the new Odourant building. This site has no generator.** **Piping: There is a live riser in place that is flanged closed, so removing it may be a consideration. There is no distribution regulation; line pressure is taken from the compressors.**	Planned							
Southeast	**80 - Niagara**	Growth	**Pass**		**3766**	Area 80 - Apartment Ensuite - New Construction*		$ 9,616	**Vertical Subdivision - A multiple unit residential building where each suite is individually metered. Issue/Concern: EGI is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers.**	Planned							
Southeast	**80 - Niagara**	Growth	**Pass**		**3769**	Area 80 - Commercial - New Construction*		$ 23,213,667	**Issue/Concern: Commercial New Construction refers to a customer intending to run a commercial business in a newly-constructed building and intending to using natural gas to meet energy needs** **Issue/Concern: EGI is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGI will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGI develops a customer additions forecast using a number of information sources: - Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities - Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates - Projections developed by external consultants specializing in population growth forecasting - Municipal long-term plans: EGI extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report. EGI reviews the following when determining feasibility: - The number of potential new customers - The consumption of natural gas by new customers - The cost of extending the gas main The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGI determines the CIAC amount and communicate with the applicant(s) in writing. Generally, there are three components of capital investments needed to support customer addition requirements: - Installation costs related to mains, services, and meters - Material costs related to mains, services and meters - Costs related to measurement and regulation equipment required to support customer growth.** **Assets: All applicable assets.** **Related Program: N/A**	Planned							
Southeast	**80 - Niagara**	Growth	**Pass**		**3770**	Area 80 - Industrial - New Construction*		$ 9,245,468	**Issue/Concern: Industrial New Construction refers to a customer intending to run an industrial manufacturing business in a newly-built facility and intending to use natural gas.** **Issue/Concern: EGI is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGI will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGI develops a customer additions forecast using a number of information sources: - Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities - Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates - Projections developed by external consultants specializing in population growth forecasting - Municipal long-term plans: EGI extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report. EGI reviews the following when determining feasibility: - The number of potential new customers - The consumption of natural gas by new customers - The cost of extending the gas main The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGI determines the CIAC amount and communicate with the applicant(s) in writing. Generally, there are three components of capital investments needed to support customer addition requirements: - Installation costs related to mains, services, and meters - Material costs related to mains, services and meters - Costs related to measurement and regulation equipment required to support customer growth.** **Assets: All applicable assets.** **Related Program: N/A**	Planned							
Southeast	**80 - Niagara**	Growth	**Pass**		**3772**	Area 80 - Residential - New Construction*		$ 53,055,300	**Issue/Concern: Residential New Construction refers to anew residential construction development of detached single homes constructed by the builder for domestic purposes.** **Issue/Concern: EGI is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGI will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGI develops a customer additions forecast using a number of information sources: - Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities - Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates - Projections developed by external consultants specializing in population growth forecasting - Municipal long-term plans: EGI extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report. EGI reviews the following when determining feasibility: - The number of potential new customers - The consumption of natural gas by new customers - The cost of extending the gas main The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGI determines the CIAC amount and communicate with the applicant(s) in writing. Generally, there are three components of capital investments needed to support customer addition requirements: - Installation costs related to mains, services, and meters - Material costs related to mains, services and meters - Costs related to measurement and regulation equipment required to support customer growth.** **Assets: All applicable assets.** **Related Program: N/A**	Planned							

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Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
Southeast	**80 - Niagara**	Growth	**Pass**		**3773**	Area 80 - Residential - Replacement*		$ 8,130,462	**Issue/Concern: Residential Replacement refers to a residential replacement customer using a fuel other than natural gas for domestic purposes and is converting to natural gas. Issue/Concern: EGI is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGI will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGI develops a customer additions forecast using a number of information sources: - Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities - Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates - Projections developed by external consultants specializing in population growth forecasting - Municipal long-term plans: EGI extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report. EGI reviews the following when determining feasibility: - The number of potential new customers - The consumption of natural gas by new customers - The cost of extending the gas main The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGI determines the CIAC amount and communicate with the applicant(s) in writing. Generally, there are three components of capital investments needed to support customer addition requirements: - Installation costs related to mains, services, and meters - Material costs related to mains, services and meters - Costs related to measurement and regulation equipment required to support customer growth. Assets: All applicable assets. Related Program: N/A**	Planned							
Southeast	**80 - Niagara**	Growth	**Pass**		**3822**	Area 80 - Commercial - Replacement*	**2028**	$ 8,819,477	**Issue/Concern: Commercial Replacement refers to a commercial replacement customer using a fuel other than natural gas for commercial business and is converting to natural gas. EGI is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGI will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGI develops a customer additions forecast using a number of information sources: - Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities - Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates - Projections developed by external consultants specializing in population growth forecasting - Municipal long-term plans: EGI extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report. EGI reviews the following when determining feasibility: - The number of potential new customers - The consumption of natural gas by new customers - The cost of extending the gas main The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGI determines the CIAC amount and communicate with the applicant(s) in writing. Generally, there are three components of capital investments needed to support customer addition requirements: - Installation costs related to mains, services, and meters - Material costs related to mains, services and meters - Costs related to measurement and regulation equipment required to support customer growth. Assets: All applicable assets. Related Program: N/A**	Planned							
Southeast	**80 - Niagara**	Growth	**Pass**		**736688**	NW 8521 Feeder Rd E Station Reinforcement SRP	**2023**	$ 309,806	**Issue/Concern/Opportunity: A new station is required to increase security of supply for Intermediate Pressure (IP) NW8521, and maintain 140 kPa as minimum system pressure in this Maximum Operating Pressure (MOP) 276 kPa system. In January 2022, 17 psig was recorded as low pressure in cold snap. Assets: District station Related Program: Not applicable**	Planned							
Southeast	**80 - Niagara**	Utilization	**Pass**		**13549**	MXGI Area 80*	**2019**	$ 26,240,787	**Meters: Meters are used to determine the gas consumption input of customer billing. The replacement program for meters is mandated by Measurement Canada. The program includes: testing, repair, and replacement requirements of meters and instruments. All verified meters are approved by Measurement Canada with an issuance of a certificate which identifies that the meter complies with Electricity and Gas Specification S-EG-02. The Company must ensure all measurement devices remain in compliance for annual audits by Measurement Canada. Measurement Canada specifies tolerances under which the meter must operate in the field. The Company must demonstrate that all aspects of its meter sampling, maintenance, and replacement comply with these criteria in order to be accredited by Measurement Canada to be an "Authorized Service Provider" and adhere to Measurement Canada's accreditation standard S-A-01. Meters may also require exchange for issues such as: damages, leaks, customer billing issues. Regulation: Regulators are the last line of defense for over-pressure to the customer. The condition of regulation systems is determined by regulator performance, corrosion of piping and regulators, and adherence to installation specifications. Failure of the regulation system can cause pressured gas to enter the premise, resulting in failure of gas equipment, loss of containment, and potentially fire or explosion.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Southeast	**Div_03 - Sarnia**	Distribution Pipe	**Pass**		**733553**	NPS 6 Retrofit	**2024**	$ 2,594,375	**Project-Specific: External Corrosion Direct Assessment (ECDA) to In-Line Inspection (ILI) Program, supporting refinement of pipeline risk profile. Associated 2025 Operations and Maintenance (O&M) spend for ILI. 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% Specified Minimum Yield Strength (SMYS). It includes installation costs for permanent 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 that are identified through the inspections.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Southeast	**Div_06 - Brantford**	Distribution Pipe	**Fail**	Dollar threshold	**1272**	Brantford North Retrofit		$ 934,148									
Southeast	**Div_06 - Brantford**	Distribution Pipe	**Fail**	Dollar threshold	**48381**	BRAN: Dist-Repl-Contr-Mains Leakage*	**2020**	$ 4,027,224									
Southeast	**Div_06 - Brantford**	Distribution Pipe	**Fail**	Dollar threshold	**48849**	BRAN - Otterville Rd. (James to Middleton) Repl. BU - Otterville	**2023**	$ 871,871									
Southeast	**Div_06 - Brantford**	Distribution Pipe	**Fail**	Dollar threshold	**48929**	BRAN - Lawrence Rd Repl. BU - Norfolk	**2023**	$ 92,564									
Southeast	**Div_06 - Brantford**	Distribution Pipe	**Fail**	Dollar threshold	**48933**	BRAN - Water St. Repl. BU - Vittoria	**2023**	$ 165,186									
Southeast	**Div_06 - Brantford**	Distribution Pipe	**Fail**	Dollar threshold	**48934**	BRAN - Rebecca St. Repl. BU - Vittoria	**2023**	$ 95,342									
Southeast	**Div_06 - Brantford**	Distribution Pipe	**Fail**	Dollar threshold	**48935**	BRAN - Colborne St. at Johnson Rd. Repl. BU - Brantford	**2023**	$ 47,842									
Southeast	**Div_06 - Brantford**	Distribution Pipe	**Fail**	Dollar threshold	**48955**	BRAN -Northern Ave. (Adams to Connaught) Repl. BU - Delhi	**2024**	$ 775,573									
Southeast	**Div_06 - Brantford**	Distribution Pipe	**Fail**	Dollar threshold	**48956**	BRAN - Connaught Ave. (Hwy 3 to Delcrest) Repl. BU - Delhi	**2024**	$ 417,724									
Southeast	**Div_06 - Brantford**	Distribution Pipe	**Fail**	Dollar threshold	**48958**	BRAN - Churchill (Connaught to Argyle) Repl. BU - Delhi	**2024**	$ 129,138									
Southeast	**Div_06 - Brantford**	Distribution Pipe	**Fail**	Dollar threshold	**48963**	BRAN - Given Rd at Lyndoch Rd Repl. BU - Norfolk	**2024**	$ 32,508									
Southeast	**Div_06 - Brantford**	Distribution Pipe	**Fail**	Dollar threshold	**48964**	BRAN - Clyde St. and North Court St. Repl. BU - Norwich	**2024**	$ 79,066									
Southeast	**Div_06 - Brantford**	Distribution Pipe	**Fail**	Dollar threshold	**48966**	BRAN - Carmen St. Repl. BU - Norwich	**2024**	$ 52,139									
Southeast	**Div_06 - Brantford**	Distribution Pipe	**Fail**	Dollar threshold	**48967**	BRAN - King St. (Ffth to Third) Repl. BU - Tillsonburg	**2024**	$ 97,798									

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Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
Southeast	Div_06 - Brantford	Distribution Pipe	Pass		48928	BRAN - Schafer Side Rd. Repl. BU - Norfolk	2023	$ 1,644,624	Project-Specific: 511907170 General: The Bare Unprotected Program is to replace all the bare and unprotected steel mains within EGI's franchise. These mains are more susceptible to leaks as they have not been cathodically protected since installation. Removing these mains from service will reduce potential for leaks due to corrosion. If this project spend is reduced or deferred, more maintenance dollars will have to be spent repairing leaks on pipe which is nearing end of life.	Planned							
Southeast	Div_06 - Brantford	Distribution Pipe	Pass		733722	NPS 12 Kirkwall-Dominion Tie-over		$ 2,211,937	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% Specified Minimum Yield Strength (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 that are identified through the inspections.	Complete	Fail	See investment description, IRPAs not appliable					
Southeast	Div_06 - Brantford	Distribution Pipe	Pass		733743	NPS 12 Guelph Reinf-Guelph Tie-over	2026	$ 4,103,386	Project-Specific: External Corrosion Direct Assessment (ECDA) to In-Line Inspection (ILI) Program, supporting refinement of pipeline risk profile. Associated 2027 Operations and Maintenance (O&M) spend for ILI. 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% Specified Minimum Yield Strength (SMYS). It includes installation costs for permanent 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 that are identified through the inspections.	Complete	Fail	See investment description, IRPAs not appliable					
Southeast	Div_06 - Brantford	Distribution Pipe	Pass		735641	Brantford Transmission Station Take-off Retrofit ECDA to ILI 2027		$ 2,081,614	Project-Specific: External Corrosion Direct Assessment (ECDA) to In-Line Inspection (ILI) Program, supporting refinement of pipeline risk profile. Associated 2029 Operations and Maintenance (O&M) spend for ILI. 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% Specified Minimum Yield Strength (SMYS). It includes installation costs for permanent 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 that are identified through the inspections.	Complete	Fail	See investment description, IRPAs not appliable					
Southeast	Div_06 - Brantford	Distribution Stations	Fail	Dollar threshold	100343	BRAN: 13T-403 Otterville Springford Distribution Station, Norwich Twp, Station Rebuild (Capital Maintenance), Proj# 06-21-701	2023	$ 90,723									
Southeast	Div_06 - Brantford	Distribution Stations	Fail	Dollar threshold	100422	BRAN: 12U-504 Simcoe Hunt Street South Distribution Station, Simcoe, Station Rebuild (Capital Maintenance)	2032	$ 2,716									
Southeast	Div_06 - Brantford	Distribution Stations	Fail	Dollar threshold	100550	BRAN: 12S-101 Tillsonburg Potter's Road Distribution Station, Tillsonburg, Station Rebuild (Capital Maintenance)	2026	$ 32,581									
Southeast	Div_06 - Brantford	Distribution Stations	Fail	Dollar threshold	100610	BRAN: 12S-202 Fernlea Farm Distribution Station, Delhi, Station Rebuild (Capital Maintenance), Proj# 06-22-701	2023	$ 239,765									
Southeast	Div_06 - Brantford	Distribution Stations	Fail	Dollar threshold	100611	BRAN: 16V-402R Dunsdon St Distribution Station, Brantford, Station Rebuild (Capital Maintenance), Proj# 06-22-704	2023	$ 257,202									
Southeast	Div_06 - Brantford	Distribution Stations	Fail	Dollar threshold	100614	BRAN: 15V-111R Stanley St Distribution Station, Brantford, Station Rebuild (Capital Maintenance), Proj# 06-22-703	2023	$ 239,765									
Southeast	Div_06 - Brantford	Distribution Stations	Fail	Dollar threshold	100624	BRAN: 12T-503 ON Energy Producer Station, Delhi, Station Rebuild (Capital Maintenance), Proj# 06-21-704	2023	$ 34,382									
Southeast	Div_06 - Brantford	Distribution Stations	Fail	Dollar threshold	100626	BRAN: 11V-101 Port Dover South Distribution Station, Port Dover, Station Rebuild (Capital Maintenance), Proj# 06-22-700	2023	$ 6,850									
Southeast	Div_06 - Brantford	Distribution Stations	Fail	Dollar threshold	100627	BRAN: 11V-101 Port Dover South Distribution Station, Port Dover, Station Rebuild (Telemetry)	2032	$ 74,690									
Southeast	Div_06 - Brantford	Distribution Stations	Fail	Dollar threshold	503639	BRAN: 17U-302 Brantford Transmission Station, Brantford, Station Rebuild (Capital Maintenance), Proj#	2023	$ 109,607									
Southeast	Div_06 - Brantford	Distribution Stations	Fail	Dollar threshold	735246	WATE: 17T-202 N.Dumphries Trans. Stn FIMP*	2031	$ 209,892									
Southeast	Div_06 - Brantford	Distribution Stations	Fail	Dollar threshold	735277	BRAN: 11V-401R Pt Ryerse Commercial St LP	2023	$ 62,277									
Southeast	Div_06 - Brantford	Distribution Stations	Fail	Dollar threshold	735278	BRAN: 09T-306R Front Street Avenue LP	2026	$ 65,161									
Southeast	Div_06 - Brantford	Distribution Stations	Fail	Dollar threshold	735279	BRAN: 11U-601R Pt Ryerse Young & Rolph W Hill LP	2023	$ 62,277									
Southeast	Div_06 - Brantford	Distribution Stations	Fail	Dollar threshold	735280	BRAN: 12R-607R Tillson Ave, South of Hyman LP	2023	$ 62,277									
Southeast	Div_06 - Brantford	Distribution Stations	Fail	Dollar threshold	735281	BRAN: 12T-506R Delhi Queen & Church Stn LP	2023	$ 62,277									
Southeast	Div_06 - Brantford	Distribution Stations	Fail	Dollar threshold	735282	BRAN: 12U-607R Simcoe Queen St S & Grove LP	2023	$ 62,277									
Southeast	Div_06 - Brantford	Distribution Stations	Fail	Dollar threshold	735283	BRAN: 12U-609R Simcoe South & John St LP	2023	$ 62,277									
Southeast	Div_06 - Brantford	Distribution Stations	Fail	Dollar threshold	735284	BRAN: 13U-603R Waterford Temperence & Leamon LP	2023	$ 62,277									
Southeast	Div_06 - Brantford	Distribution Stations	Fail	Dollar threshold	735285	BRAN: 15U-301R St Paul & Dublin LP	2023	$ 62,277									
Southeast	Div_06 - Brantford	Distribution Stations	Fail	Dollar threshold	735287	BRAN: 15V-406R Mohawk Brighton LP	2023	$ 62,277									
Southeast	Div_06 - Brantford	Distribution Stations	Fail	Dollar threshold	735313	BRAN: 15U-308R Brantford Grand & Jubilee LP	2023	$ 62,277									
Southeast	Div_06 - Brantford	Distribution Stations	Fail	Dollar threshold	735319	BRAN: 15V-408R Brighton & Superior LP	2023	$ 62,277									
Southeast	Div_06 - Brantford	Distribution Stations	Fail	Dollar threshold	735326	BRAN: 11V-202R Pt Dover Nelson & George St LP	2024	$ 64,081									
Southeast	Div_06 - Brantford	Distribution Stations	Fail	Dollar threshold	735327	BRAN: 11V-204R Pt Dover Clinton & St Patrick LP	2024	$ 64,081									
Southeast	Div_06 - Brantford	Distribution Stations	Fail	Dollar threshold	735328	BRAN: 09T-303R Church St & Erie Ave LP	2023	$ 62,277									
Southeast	Div_06 - Brantford	Distribution Stations	Fail	Dollar threshold	735329	WATE: 09T-307R Ellis & Alley St LP	2024	$ 64,081									
Southeast	Div_06 - Brantford	Distribution Stations	Fail	Dollar threshold	735330	BRAN: 12R-302R Victoria St & Niagara St Station LP	2023	$ 62,277									
Southeast	Div_06 - Brantford	Distribution Stations	Fail	Dollar threshold	735331	BRAN: 12R-303R Tillson Ave Dist Station LP	2024	$ 64,081									
Southeast	Div_06 - Brantford	Distribution Stations	Fail	Dollar threshold	735332	BRAN: 12U-501 Simcoe Queen St South of Hwy 3 (2nd Stage) LP	2024	$ 64,081									
Southeast	Div_06 - Brantford	Distribution Stations	Fail	Dollar threshold	735333	BRAN: 12U-602R Simcoe Union & Talbot Stn LP	2024	$ 64,081									

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Southeast	**Div_06 - Brantford**	Distribution Stations	**Fail**	Dollar threshold	**735334**	BRAN: 12U-606R Simcoe Metcalfe & Robinson LP	**2023**	$ 62,277									
Southeast	**Div_06 - Brantford**	Distribution Stations	**Pass**		**103426**	BRAN: 16U-601 Brantford Gate Station, Station Rebuild (Capital Maintenance), Proj# 57-22-701	**2023**	$ 9,179,558	**Issue/Concern/Opportunity: Rebuild entire station to address station integrity issues, maintenance/operational issues, and also allow for additional load capacity through the Eastern Transmission system.** **Justification: A full rebuild will correct station integrity issues, maintenance/operational issues, and enable additional capacity.** **Assets: Brantford Gate Station (16U-601)** **Related Investments: Not applicable.**	Planned							
Southeast	**Div_06 - Brantford**	Growth	**Pass**		**48379**	BRAN: Company Program - New Business - Scattered Mains - Contractor*	**2020**	$ 12,733,740	**Scattered Mains**	Planned							
Southeast	**Div_06 - Brantford**	Growth	**Pass**		**500419**	BRAN: Company Program - Customer Connections*		$ 31,915,261	**Brantford Customer Connections Program Items**	Planned							
Southeast	**Div_06 - Brantford**	Utilization	**Pass**		**48386**	BRAN: Meter & Regulator Inst Repl-Contractor*	**2020**	$ 21,705,029	**Meter & Reg Install- Replacement**	Complete	**Fail**	See investment description, IRPAs not appliable					
Southeast	**Div_07 - Waterloo**	Distribution Pipe	**Fail**	Dollar threshold	**1282**	Owen Sound Section 2 Retrofit		$ 992,352									
Southeast	**Div_07 - Waterloo**	Distribution Pipe	**Fail**	Dollar threshold	**48398**	WATE: Dist-Repl-Contr-Services*	**2020**	$ 11,786,291									
Southeast	**Div_07 - Waterloo**	Distribution Pipe	**Fail**	Dollar threshold	**48936**	WATE - Hamilton St. Repl. BU - Cambridge	**2023**	$ 593,079									
Southeast	**Div_07 - Waterloo**	Distribution Pipe	**Fail**	Dollar threshold	**48937**	WATE - Glen Morris (Selkirk to Stanley) Repl. BU - Cambridge	**2023**	$ 194,377									
Southeast	**Div_07 - Waterloo**	Distribution Pipe	**Fail**	Dollar threshold	**733713**	NPS 12 Owen Sound Section 1 Retrofit		$ 934,148									
Southeast	**Div_07 - Waterloo**	Distribution Pipe	**Fail**	Dollar threshold	**733714**	NPS 6 Hawtrey Trans. Station Take-off Replacement	**2023**	$ 498,212									
Southeast	**Div_07 - Waterloo**	Distribution Pipe	**Fail**	Timing	**1269**	Owen Sound Section 1 Retrofit	**2023**	$ 1,992,848				Within 3 years, supply side not applicable					
Southeast	**Div_07 - Waterloo**	Distribution Pipe	**Pass**		**30234**	Div. 06 - Brant - Broadway St W - Southeast - Waterloo - 1378	**2032**	$ 5,408,534	**Div. 06 - Brant - Broadway St. W. - Southeast - Waterloo - 1378** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: Brantford is currently doing a lot of road reconstruction around this area. Contact municipality to see which roads have been recently redone - project has been updated to reflect moratorium until 2026.**	Planned							
Southeast	**Div_07 - Waterloo**	Distribution Pipe	**Pass**		**30237**	Div. 06 - Brantford - Abigail Ave - Southeast - Waterloo - 1309	**2032**	$ 3,398,728	**Div. 06 - Brantford - Abigail Ave - Southeast - Waterloo - 1309** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: Every home will require a new farm tap.**	Planned							
Southeast	**Div_07 - Waterloo**	Distribution Pipe	**Pass**		**30238**	Div. 06 - Brantford - Balmoral Dr - Southeast - Waterloo - 1291	**2030**	$ 3,118,012	**Div. 06 - Brantford - Balmoral Dr. - Southeast - Waterloo - 1291** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: Station 11T-440 may need to be rebuilt as part of the project.**	Planned							
Southeast	**Div_07 - Waterloo**	Distribution Pipe	**Pass**		**30243**	Div. 06 - Brantford - Dundas St E - Southeast - Waterloo - 1303	**2028**	$ 2,095,706	**Div. 06 - Brantford - Dundas St. E. - Southeast - Waterloo - 1303** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
Southeast	**Div_07 - Waterloo**	Distribution Pipe	**Pass**		**30244**	Div. 06 - Brantford - Elgin St - Southeast - Waterloo - 1296	**2032**	$ 5,590,098	**Div. 06 - Brantford - Elgin St. - Southeast - Waterloo - 1296** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: Some of the piping is inside of Brantford Balmoral Gate Station (16U-602). Scope of project would require a bypass of station to install the new inlet and outlet. There is a history of mercury in the soil in and around the Brantford Balmoral Gate Station, so soil assessments will be required.**	Planned							
Southeast	**Div_07 - Waterloo**	Distribution Pipe	**Pass**		**30245**	Div. 06 - Brantford - Ewing Dr - Southeast - Waterloo - 1316	**2029**	$ 3,311,557	**Div. 06 - Brantford - Ewing Dr. - Southeast - Waterloo - 1316** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: City of Brantford is restoring Wood St. and Charing Cross. Project was updated to reflect a moratorium until 2026.**	Planned							

* in the Investment Name indicates a program item. Program items are unique as they represent numerous projects grouped together and budgeted in advance. This results in forecast spend appearing larger than it would at the project level and it also impacts the in-service dates

Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
Southeast	**Div_07 - Waterloo**	Distribution Pipe	**Pass**		**30246**	Div. 06 - Brantford - Franklin St - Southeast - Waterloo - 1388	**2031**	$ 4,963,682	**Div. 06 - Brantford - Franklin St. - Southeast - Waterloo - 1388** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
Southeast	**Div_07 - Waterloo**	Distribution Pipe	**Pass**		**30248**	Div. 06 - Brantford - Greenwich St - Southeast - Waterloo - 1332	**2029**	$ 3,486,632	**Div. 06 - Brantford - Greenwich St - Southeast - Waterloo - 1332** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
Southeast	**Div_07 - Waterloo**	Distribution Pipe	**Pass**		**30252**	Div. 06 - Brantford - St George St - Southeast - Waterloo - 1312	**2031**	$ 5,813,159	**Div. 06 - Brantford - St. George St. - Southeast - Waterloo - 1312** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
Southeast	**Div_07 - Waterloo**	Distribution Pipe	**Pass**		**30253**	Div. 06 - Brantford - St George St 2 - Southeast - Waterloo - 1386	**2030**	$ 6,018,336	**Div. 06 - Brantford - St. George St. 2 - Southeast - Waterloo - 1386** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: MTO permit may be required and it is a lengthy process.**	Planned							
Southeast	**Div_07 - Waterloo**	Distribution Pipe	**Pass**		**30256**	Div. 06 - Brantford - Toll Gate Rd - Southeast - Waterloo - 1314	**2029**	$ 3,565,964	**Div. 06 - Brantford - Toll Gate Rd. - Southeast - Waterloo - 1314** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: Piping on Hill Ave. from Charing Cross to Wood St. was replaced with NPS 2 PE in 2021 as part of 06-21-609 Hill Ave. (Charing Cross to Wood St.) replacement project. The City of Brantford is restoring Hill Ave., Wood St. and Charing Cross. Pipe on Hill Ave. from Charing Cross to Wood St. was replaced in 2021. This project was updated to reflect a moratorium until 2026.**	Planned							
Southeast	**Div_07 - Waterloo**	Distribution Pipe	**Pass**		**30260**	Div. 06 - Norfolk County - Andy's Corners - Norfolk County Rd 21 - Southeast - Waterloo - 1325	**2028**	$ 1,674,985	**Div. 06 - Norfolk County - Andy's Corners - Norfolk County Rd. 21 - Southeast - Waterloo - 1325** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: Customer station 12U-327C will need to be shut down and monetary compensation may be required. Producer station 12U-301 may need to be built. Inlet gas is not owned by EGI and coordination is required. Farm taps will need to be built for every service.**	Planned							
Southeast	**Div_07 - Waterloo**	Distribution Pipe	**Pass**		**30266**	Div. 06 - Norfolk County - Tillsonburg - 3rd Concession Rd N - Southeast - Waterloo - 1310	**2031**	$ 4,084,703	**Div. 06 - Norfolk County - Tillsonburg - 3rd Concession Rd. N. - Southeast - Waterloo - 1310** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: There is a rail crossing.**	Planned							
Southeast	**Div_07 - Waterloo**	Distribution Pipe	**Pass**		**30267**	Div. 06 - Tillsonburg - Brownsville Rd - Southeast - Waterloo - 1391	**2027**	$ 2,548,549	**Div. 06 - Tillsonburg - Brownsville Rd. - Southeast - Waterloo - 1391** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: There are inside regulators and wall-to-wall concrete in downtown core.**	Complete	**Fail**	NPS 2, cannot downsize or retire					
Southeast	**Div_07 - Waterloo**	Distribution Pipe	**Pass**		**30269**	Div. 06 - Tillsonburg - Potters Rd - Southeast - Waterloo - 1375	**2028**	$ 2,759,507	**Div. 06 - Tillsonburg - Potters Rd. - Southeast - Waterloo - 1375** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Complete	**Fail**	NPS 2, cannot downsize or retire					

Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
Southeast	**Div_07 - Waterloo**	Distribution Pipe	**Pass**		**30270**	Div. 06 - Tillsonburg - Quarter Town Line - Southeast - Waterloo - 1383	**2032**	$ 4,182,288	**Div. 06 - Tillsonburg - Quarter Town Line - Southeast - Waterloo - 1383** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: Geotechnical assessments are required. Installation across Grand River required. Large industrial customers would require planned shutdowns as a result of replacement. Permitting can be lengthy.**	Planned							
Southeast	**Div_07 - Waterloo**	Distribution Pipe	**Pass**		**30272**	Div. 06 - Tillsonburg - Victoria St - Southeast - Waterloo - 1324	**2030**	$ 2,085,173	**Div. 06 - Tillsonburg - Victoria St. - Southeast - Waterloo - 1324** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: Reconstruction of Union St. (Moore St. to Margaret St.) is proposed sometime in the future by City of Waterloo; however, timing/funding has not been confirmed as it is a lower-priority project for them. Also, Union St., Waterloo (King St. to Moore St.), just east of the limits of this project, is scheduled for reconstruction by City of Waterloo for 2022 – 2023.**	Planned							
Southeast	**Div_07 - Waterloo**	Distribution Pipe	**Pass**		**48397**	WATE: Dist-Repl-Contr-Mains Municipal*	**2020**	$ 105,647,508	**General: Projects in the relocation category are capital expenditures required to replace or relocate segments of pipeline in order to accommodate municipal infrastructure work. The cost sharing for this work is managed through the Franchise Agreements established with municipalities. A consultative approach is used between the municipality and EGI to avoid conflicts with municipal infrastructure early in the planning stage. If a conflict is unavoidable, pipeline assets are typically relocated or replaced.**	Planned							
Southeast	**Div_07 - Waterloo**	Distribution Pipe	**Pass**		**48409**	WATE: Anodes*	**2020**	$ 8,337,038	**General: The anodes program within the corrosion program includes the required expenditure to install anodes in order to reduce the amount of down plant within EGI's 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.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Southeast	**Div_07 - Waterloo**	Distribution Pipe	**Pass**		**733619**	NPS 12 Owen Sound Reinforcement Retrofit		$ 1,763,772	**Project-Specific: External Corrosion Direct Assessment (ECDA) to In-Line Inspection (ILI) Program, supporting refinement of pipeline risk profile. Associated 2027 Operations and Maintenance (O&M) spend for ILI.** **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% SMYS. It includes installation costs for permanent 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 that are identified through the inspections.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Southeast	**Div_07 - Waterloo**	Distribution Pipe	**Pass**		**735796**	NPS 12 Waterloo-Erbsville Take-Off Project, Dig Site 37		$ 1,743,742	**2022 forecast: One dig based on previous years ECDA.** **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% Specified Minimum Yield Strength (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 that are identified through the inspections.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Southeast	**Div_07 - Waterloo**	Distribution Stations	**Fail**	Dollar threshold	**48418**	WATE: 19V-105R Stone & Gordon Vault Station, Guelph, Station Rebuild (Capital Maintenance), Proj# 07-19-702	**2023**	$ 800,378									
Southeast	**Div_07 - Waterloo**	Distribution Stations	**Fail**	Dollar threshold	**49057**	WATE: 19R-501R Wellesley Distribution Station, Wellesley Twp, Station Rebuild (Load Growth), Proj# 07-21-703	**2023**	$ 62,277									
Southeast	**Div_07 - Waterloo**	Distribution Stations	**Fail**	Dollar threshold	**100240**	WATE: Mt Elgin Dist Stn, Mt Elgin, Station	**2027**	$ 156,107									
Southeast	**Div_07 - Waterloo**	Distribution Stations	**Fail**	Dollar threshold	**100615**	WATE: 17T-202 North Dumfries Distribution Station, North Dumfries, Station Rebuild (Obsolete Heater)	**2023**	$ 112,098									
Southeast	**Div_07 - Waterloo**	Distribution Stations	**Fail**	Dollar threshold	**100617**	WATE: 18U-504 Cambridge East Distribution Station, Cambridge, Station Rebuild (Obsolete Heater)	**2024**	$ 961,214									
Southeast	**Div_07 - Waterloo**	Distribution Stations	**Fail**	Dollar threshold	**100829**	WATE: 19U-601 Guelph Highway 24 Gate Station, Guelph, Station Rebuild (Capital Maintenance), Proj# 07-21-711	**2023**	$ 623,388									
Southeast	**Div_07 - Waterloo**	Distribution Stations	**Fail**	Dollar threshold	**100833**	WATE: 21T-301 Salem Gate Station, Salem, Station Rebuild (Capital Maintenance), Proj# 07-22-700	**2023**	$ 232,914									
Southeast	**Div_07 - Waterloo**	Distribution Stations	**Fail**	Dollar threshold	**100912**	WATE: 23Q-301 Harriston Gate Station, Harriston, Station Rebuild (Capital Maintenance), Proj# 07-21-713	**2023**	$ 498,212									
Southeast	**Div_07 - Waterloo**	Distribution Stations	**Fail**	Dollar threshold	**101092**	HALT-440 Harrop	**2025**	$ 387,435									
Southeast	**Div_07 - Waterloo**	Distribution Stations	**Fail**	Dollar threshold	**503214**	WATE: 19S-603 Waterloo-Laurel Creek Station, Waterloo, Station Rebuild (Capital Maintenance), Proj# 07-22-705	**2023**	$ 239,765									
Southeast	**Div_07 - Waterloo**	Distribution Stations	**Fail**	Dollar threshold	**503215**	WATE: 22T-501R Alma Distribution Station, Alma, Station Rebuild (Capital Maintenance), Proj# 07-21-707	**2031**	$ 637,751									
Southeast	**Div_07 - Waterloo**	Distribution Stations	**Fail**	Dollar threshold	**735226**	WATE: 19U-201 Guelph West Gate Stn. FIMP	**2023**	$ 186,830									
Southeast	**Div_07 - Waterloo**	Distribution Stations	**Fail**	Dollar threshold	**735235**	WATE: 21s-601 Fergus 1st Trans Stn FIMP*	**2031**	$ 351,367									
Southeast	**Div_07 - Waterloo**	Distribution Stations	**Fail**	Dollar threshold	**735239**	WATE: 19S-201 Heidelburg Gate FIMP*	**2032**	$ 203,699									
Southeast	**Div_07 - Waterloo**	Distribution Stations	**Fail**	Dollar threshold	**735247**	WATE: 23R-602 Rothsay Trans Stn,FIMP*	**2032**	$ 193,718									
Southeast	**Div_07 - Waterloo**	Distribution Stations	**Fail**	Dollar threshold	**735248**	WATE: 18S-401 Markdale Stn. FIMP*	**2028**	$ 206,426									
Southeast	**Div_07 - Waterloo**	Distribution Stations	**Fail**	Dollar threshold	**735249**	BRAN: 14S-601 Norwich Brick Gate Stn. FIMP	**2030**	$ 212,212									
Southeast	**Div_07 - Waterloo**	Distribution Stations	**Fail**	Dollar threshold	**735250**	WATE: 17T-201 New Dundee Gate Stn FIMP	**2030**	$ 212,212									
Southeast	**Div_07 - Waterloo**	Distribution Stations	**Fail**	Dollar threshold	**735252**	WATE: 18T-402 Mannheim Trans Stn	**2032**	$ 203,699									
Southeast	**Div_07 - Waterloo**	Distribution Stations	**Fail**	Dollar threshold	**735258**	WATE: 19U-601R Rozelle Rd. Dist. Stn FIMP	**2030**	$ 212,212									
Southeast	**Div_07 - Waterloo**	Distribution Stations	**Fail**	Dollar threshold	**735260**	WATE: 22S-402 Moorefield Dist. Stn. FIMP	**2030**	$ 212,212									
Southeast	**Div_07 - Waterloo**	Distribution Stations	**Fail**	Dollar threshold	**735262**	WATE: 30N-501 Southhampton Gate Stn. FIMP	**2032**	$ 203,699									
Southeast	**Div_07 - Waterloo**	Distribution Stations	**Fail**	Dollar threshold	**735263**	WATE: 30Q-105C Sutherland Downs Pit FIMP	**2032**	$ 203,699									
Southeast	**Div_07 - Waterloo**	Distribution Stations	**Fail**	Dollar threshold	**735269**	WATE: 12T-102 Norwich-Middleton Town Stn. FIMP	**2030**	$ 212,212									
Southeast	**Div_07 - Waterloo**	Distribution Stations	**Fail**	Dollar threshold	**735307**	WATE: 18U-205R Hungerford & Walker LP	**2023**	$ 62,277									

* in the Investment Name indicates a program item. Program items are unique as they represent numerous projects grouped together and budgeted in advance. This results in forecast spend appearing larger than it would at the project level and it also impacts the in-service dates

Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
Southeast	**Div_07 - Waterloo**	Distribution Stations	**Fail**	Dollar threshold	**735308**	WATE: 18U-220R Bechtel & Millvue LP	**2023**	$ 62,277									
Southeast	**Div_07 - Waterloo**	Distribution Stations	**Fail**	Dollar threshold	**735310**	WATE: 18U-407R Church & Sherring LP	**2023**	$ 62,277									
Southeast	**Div_07 - Waterloo**	Distribution Stations	**Fail**	Dollar threshold	**735320**	WATE: 17U-211R Stanley @ Glenmorris LP	**2023**	$ 62,277									
Southeast	**Div_07 - Waterloo**	Distribution Stations	**Fail**	Dollar threshold	**735321**	WATE: 17U-214R Middleton St at Waterworks LP	**2023**	$ 62,277									
Southeast	**Div_07 - Waterloo**	Distribution Stations	**Fail**	Dollar threshold	**735322**	WATE: 18U-403R Agnes & William LP	**2023**	$ 62,277									
Southeast	**Div_07 - Waterloo**	Distribution Stations	**Fail**	Dollar threshold	**735324**	WATE: 18U-418R 122 Dolph St N LP	**2023**	$ 62,277									
Southeast	**Div_07 - Waterloo**	Distribution Stations	**Fail**	Dollar threshold	**735325**	WATE: 18U-506R Bishop & King LP	**2023**	$ 62,277									
Southeast	**Div_07 - Waterloo**	Distribution Stations	**Pass**		**503275**	Waterloo/Brantford PFM Compliance Program*		$ 1,190,069	**Issue/Concern/Opportunity: -PFMs that require a bypass will be rebuilt w/bypass to the new standard: oWhen they are due for a meter exchange and in the meter seal expiry year, provided that year is between 2022 and 2026. This will fall under the meter exchange budget and costs are not covered in this program. oIf the meter seal year is not between 2022 and 2026, the set will be rebuilt with a bypass the year after it is inspected. This will allow the technicians to identify which will require rebuilt at the time of inspection, and Sohan and I will be developing a process to get work orders generated for these rebuilds after the inspection. Also ensures that we focus our efforts on rebuilding active PFMs requiring rebuild. While I originally mentioned a proactive strategy to rebuild prior to the inspection year, we decided against that. -Assumption is that 50% of PFMs will need to be rebuilt. -Calculations are based on an estimate of $5500 per rebuild. As you know there is a significant swing depending on the pipe size, volume, existing set up (first stage cut, etc) that may influence this including the release of the new SEADs designs, that I have not seen yet.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Southeast	**Div_07 - Waterloo**	Growth	**Pass**		**30527**	SRP_Southeast_Baden_18S-501STN_Rebuild	**2029**	$ 956,425	**Increase capacity.**	Planned							
Southeast	**Div_07 - Waterloo**	Growth	**Pass**		**30528**	SRP_Southeast_Baden_Peel St_Reinforcement_NPS6_400m_420kPa	**2028**	$ 644,963	**New reinforcement main along Bleams Rd. E. is required.**	Planned							
Southeast	**Div_07 - Waterloo**	Growth	**Pass**		**30529**	SRP_Southeast_Brantford_Maple Grove Rd_Reinforcement_NPS6_830m_420kPa	**2027**	$ 1,323,087	**Pipe reinforcement required to maintain system pressures due to growth**	Planned							
Southeast	**Div_07 - Waterloo**	Growth	**Pass**		**30530**	SRP_Southeast_Breslau_19T-601RSTN_Rebuild	**2028**	$ 1,350,208	**Increase capacity.**	Planned							
Southeast	**Div_07 - Waterloo**	Growth	**Pass**		**30532**	SRP_Southeast_Breslau_Sawmill Rd_Reinforcement_NPS4_500m_3450kPa	**2027**	$ 797,040	**High Pressure (HP) reinforcement along Sawmill Rd. is required.**	Planned							
Southeast	**Div_07 - Waterloo**	Growth	**Pass**		**30533**	SRP_Southeast_Breslau_Sawmill Rd_Reinforcement_NPS4_900m_3450kPa	**2032**	$ 1,550,035	**High Pressure (HP) reinforcement is required along Sawmill Rd. This is a continuation of project SRPR OSGW 2027_005.**	Planned							
Southeast	**Div_07 - Waterloo**	Growth	**Pass**		**30536**	SRP_Southeast_Cambridge_Guelph Ave_Reinforcement_NPS6_1000m_420kPa	**2026**	$ 1,467,640	**Reinforce existing main along Guelph Ave. in Cambridge with 1,000 m NPS 6 PE.**	Planned							
Southeast	**Div_07 - Waterloo**	Growth	**Pass**		**30537**	SRP_Southeast_Cambridge_Pinebush Rd_Reinforcement_NPS6_470m_420kPa	**2023**	$ 614,669	**Reinforce existing NPS 2 PE along Pinbush Rd. with approximately 470 m NPS 6 PE. Project has been pushed to 2023.**	Planned							
Southeast	**Div_07 - Waterloo**	Growth	**Pass**		**30540**	SRP_Southeast_Kitchener_Bleams_Reinforcement_NPS12_10m_6160kPa	**2023**	$ 809,595	**Install an above-grade valve site with 12-inch crossover and scraper bar tees.**	Planned							
Southeast	**Div_07 - Waterloo**	Growth	**Pass**		**30541**	SRP_Southeast_Listowel_21Q-103RSTN_Rebuild	**2024**	$ 411,015	**Increase capacity and maximum sustainable.**	Planned							
Southeast	**Div_07 - Waterloo**	Growth	**Pass**		**30542**	SRP_Southeast_Owen Sound_County Rd 40_Reinforcement_NPS12_11800m_4670kPa	**2025**	$ 34,094,285	**Loop existing 10-inch Steel 4,670 kPa main from existing PH4 reinforcement to Squire, Ontario with 12-inch steel main. Install valve site and 12-inch receiver facilities.**	Planned							
Southeast	**Div_07 - Waterloo**	Growth	**Pass**		**30545**	SRP_Southeast_Port Elgin_29N-101STN_Rebuild	**2024**	$ 1,318,144	**Increase capacity.**	Planned							
Southeast	**Div_07 - Waterloo**	Growth	**Pass**		**30547**	SRP_Southeast_Southampton_30N-501STN_Rebuild	**2030**	$ 1,335,240	**Increase capacity.**	In Progress							
Southeast	**Div_07 - Waterloo**	Growth	**Pass**		**30548**	SRP_Southeast_Southampton_South St_Reinforcement_NPS6_600m_550kPa	**2028**	$ 967,445	**A new main from Railway Rd. running along South St. is required.**	In Progress							
Southeast	**Div_07 - Waterloo**	Growth	**Pass**		**48396**	WATE: Company Program - New Business - Scattered Mains - Contractor*	**2020**	$ 29,699,613	**Scattered Mains**	Planned							
Southeast	**Div_07 - Waterloo**	Growth	**Pass**		**48998**	WATE - Breslau System Reinforcement	**2022**	$ 2,816	**Issue/Concern/Opportunity: System Reinforcement - Loop existing 2-inch PE with 1,300 m 6-inch PE along Victoria Rd. S. from Clair Rd. E. southerly to #1953 Victoria Ave. S. tying into NPS 4 PE main. (WAT FBPR 2022_1) Per Distribution Optimization Engineering (DOE) 2021 System Reinforcement Plan (SRP). Asset: 2-inch PE with 1,300 m 6-inch PE along Victoria Rd. S. from Clair Rd. E. southerly to #1953 Victoria Ave. S. tying into NPS 4 PE main. (WAT FBPR 2022_1) Related Program: N/A**	Planned							
Southeast	**Div_07 - Waterloo**	Growth	**Pass**		**49079**	SRP_Southeast_Guelph_Victoria Rd S_Reinforcement_NPS6_1500m_420kPa	**2026**	$ 1,204,126	**Issue/Concern/Opportunity: System Reinforcement - Loop existing 2-inch PE with 1,300 m 6-inch PE along Victoria Rd. S. from Clair Rd. E. southerly to #1953 Victoria Ave. S. tying into NPS 4 PE main. (WAT FBPR 2022_1) Per Distribution Optimization Engineering (DOE) 2021 System Reinforcement Plan (SRP) review, project was deferred from 2022 to 2026. Asset: 2-inch PE with 1,300 m 6-inch PE along Victoria Rd. S. from Clair Rd. E. southerly to #1953 Victoria Ave. S. tying into NPS 4 PE main. (WAT FBPR 2022_1) Related Program: N/A**	Planned							
Southeast	**Div_07 - Waterloo**	Growth	**Pass**		**49104**	WATE: Starlight Dist Stn, Meaford, Growth	**2025**	$ 14,978	**Issue/Concern/Opportunity: Station is to be rebuilt with 9.S-150FR. There is over-capacity due to load additions. Asset: Station ID: 31T-102R. Related Program: N/A**	Planned							
Southeast	**Div_07 - Waterloo**	Growth	**Pass**		**49105**	WATE: Baden Dist Stn, Baden, Growth	**2025**	$ 1,056,821	**Issue/Concern/Opportunity: A new distribution station for growth in Baden off the 6,160 kPa system delivering 1,900 kPa outlet is required. Predicted flow of 8,000 m3/h is required. It is a similar station to 18S-374 in 2018. EGI is not meeting minimum inlets at 19R-501R (Wellesley District Regulating Station) and 19R-502R (Hammer District Regulating Station). This project may be pushed into 2024 but need it to be flowing in 2024. This has been deferred to 2025 per the 2021 System Reinforcement Plan (SRP) updates. Asset: 19R-501R (Wellesley District Regulating Station) and 19R-502R (Hammer District Regulating Station) Related Program: N/A**	Planned							
Southeast	**Div_07 - Waterloo**	Growth	**Pass**		**49149**	WATE - Mount Forest System Reinforcement	**2027**	$ 388,568	**Issue/Concern/Opportunity: A system reinforcement is required. Loop 2-inch PE with 4-inch PE along Main St. N. 600 m NPS 4 PE from Sligo Rd. to Cora Lea St. Minimum pressures are NW of town. (WAT FBPR 2025_4) Asset: Main St. N. 600 m NPS 4 PE from Sligo Rd. to Cora Lea St. Related Program: N/A**	Planned							
Southeast	**Div_07 - Waterloo**	Growth	**Pass**		**49794**	WATE: Listowel System Reinforcement, Proj# 07-21-705	**2023**	$ 1,743,742	**Listowel - 1.9 km of 6-inch ST at 1,900 kPa MOP. This project in conjunction with the 2024 project will accommodate approximately 5 years' growth on the Listowel lateral starting in 2023, preferred alternative is MOP upgrade. This project has 2021 prework (direct assessment, etc.). Results of the prework may change the 2024 capital requirements.**	Planned							
Southeast	**Div_07 - Waterloo**	Growth	**Pass**		**100831**	WATE: 21U-101 Fergus Second Stage, Fergus, Station Rebuild (Load Growth), Proj#	**2023**	$ 890,554	**Issue/Concern/Opportunity: Station is expected to be at capacity in 2023. Rebuild is required to restore capacity for Fergus system and enable additional growth. Assets: 21U-101 Fergus Second Stage Related Program: Not applicable**	Planned							

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Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
Southeast	**Div_07 - Waterloo**	Growth	**Pass**		**500420**	WATE: Company Program - Customer Connections*		$ 88,065,710	**Waterloo Customer Connections Program Items**	Planned							
Southeast	**Div_07 - Waterloo**	Utilization	**Pass**		**48406**	WATE: Meter & Regulator Inst Repl-Contractor*	**2020**	$ 50,721,225	**Meter & Reg Install- Replacement**	Complete	**Fail**	See investment description, IRPAs not appliable					
Southeast	**Div_07 - Waterloo**	Transmission Pipe & Underground Storage	**Pass**		**735006**	Trafalgar NPS 26 - Line Lowering	**2023**	$ 6,352,204	**Project-Specific: Replacement of 6 sections (1.3 km, 0.5 km, 0.2 km, two small depth-of-cover areas, and a stream crossing) of NPS 26 of the Trafalgar Lines due to depth-of-cover issues found.** **General: Sections of the NPS 26 Trafalgar pipeline have been identified as shallow with depth of cover below the minimum permissible by TSSA. This project will mitigate these areas by lowering the pipeline through these areas. There will be two to three segments lowered within the Galt Gate-Kirkwall segment.** **Mitigation of depth-of-cover sites that are out of compliance with CSA Z662 and TSSA requirements will be necessary. Some of the known sites are discovered during annual Depth of Cover Surveying, while others are reported by company crews when performing maintenance work or by a third party. At this time, the specific work scope of each year is not defined and this is a blanket program as a placeholder in the budget. The mitigation work will include the construction costs from sites identified and planned for the current year, as well as work on sites that are newly identified. Scope of work can vary from small remediation projects to add fill, concrete or bank stabilization, to short replacement of pipe.**	Planned							
Southeast	**Div_16 - Hamilton**	Distribution Pipe	**Fail**	Dollar threshold	**30400**	Div. 16 - Haldimand - Fisherville - Erie Ave N 2 - Hamilton - 1730	**2030**	$ 1,696,337									
Southeast	**Div_16 - Hamilton**	Distribution Pipe	**Fail**	Dollar threshold	**30409**	Div. 16 - Hamilton - Oak Ave - Hamilton - 1818	**2027**	$ 1,463,707									
Southeast	**Div_16 - Hamilton**	Distribution Pipe	**Fail**	Dollar threshold	**30410**	Div. 16 - Hamilton - Province St N - Hamilton - 1416	**2028**	$ 1,223,329									
Southeast	**Div_16 - Hamilton**	Distribution Pipe	**Fail**	Dollar threshold	**30411**	Div. 16 - Hamilton - Rosemary Ave - Hamilton - 1731	**2030**	$ 1,477,245									
Southeast	**Div_16 - Hamilton**	Distribution Pipe	**Fail**	Dollar threshold	**48429**	HAMI: Dist-Repl-Contr-Mains Leakage*	**2019**	$ 4,822,388									
Southeast	**Div_16 - Hamilton**	Distribution Pipe	**Fail**	Dollar threshold	**48430**	HAMI: Dist-Repl-Contr-Services*	**2020**	$ 4,788,742									
Southeast	**Div_16 - Hamilton**	Distribution Pipe	**Fail**	Dollar threshold	**48788**	HAMI-Haldimand Trail - Dunn	**2024**	$ 433,354									
Southeast	**Div_16 - Hamilton**	Distribution Pipe	**Fail**	Dollar threshold	**48910**	HAMI-South Coast - Walpole	**2023**	$ 107,614									
Southeast	**Div_16 - Hamilton**	Distribution Pipe	**Fail**	Dollar threshold	**48912**	HAMI - HWY 6 - Walpole	**2023**	$ 197,292									
Southeast	**Div_16 - Hamilton**	Distribution Pipe	**Fail**	Dollar threshold	**48939**	HAMI: Haldimand Rd 12, Rainham, BU Replacement	**2023**	$ 95,906									
Southeast	**Div_16 - Hamilton**	Distribution Pipe	**Fail**	Dollar threshold	**48940**	HAMI- Taylor - Dunnville	**2023**	$ 92,654									
Southeast	**Div_16 - Hamilton**	Distribution Pipe	**Fail**	Dollar threshold	**48941**	HAMI- Albion - York	**2023**	$ 22,420									
Southeast	**Div_16 - Hamilton**	Distribution Pipe	**Fail**	Dollar threshold	**48953**	HAMI- Upper Wellington - Hamilton	**2024**	$ 171,737									
Southeast	**Div_16 - Hamilton**	Distribution Pipe	**Fail**	Dollar threshold	**48954**	HAMI- Rainham Road - Walpole	**2023**	$ 684,543									
Southeast	**Div_16 - Hamilton**	Distribution Pipe	**Fail**	Dollar threshold	**48977**	HAMI - Haldimand road 55 - Walpole	**2023**	$ 269,035									
Southeast	**Div_16 - Hamilton**	Distribution Pipe	**Fail**	Dollar threshold	**48983**	HAMI - Park - Hamilton	**2024**	$ 57,416									
Southeast	**Div_16 - Hamilton**	Distribution Pipe	**Fail**	Dollar threshold	**48984**	HAMI - Mohawk - Hamilton	**2024**	$ 64,594									
Southeast	**Div_16 - Hamilton**	Distribution Pipe	**Fail**	Dollar threshold	**48985**	HAMI - Main at Leland - Hamilton	**2024**	$ 173,341									
Southeast	**Div_16 - Hamilton**	Distribution Pipe	**Fail**	Dollar threshold	**100843**	HAMI: 295 Dundas St E Shallow Main Waterdown	**2028**	$ 166,458									
Southeast	**Div_16 - Hamilton**	Distribution Pipe	**Fail**	Dollar threshold	**100924**	HAMI: Jackson Street Leakage, Hamilton, Leakage	**2023**	$ 1,252,371									
Southeast	**Div_16 - Hamilton**	Distribution Pipe	**Fail**	Dollar threshold	**100928**	Park St, Jarvis	**2023**	$ 58,291									
Southeast	**Div_16 - Hamilton**	Distribution Pipe	**Fail**	Dollar threshold	**101631**	HAMI: Lloyminn/Crestview, Ancaster, Replacement	**2023**	$ 1,342,370									
Southeast	**Div_16 - Hamilton**	Distribution Pipe	**Fail**	Dollar threshold	**733609**	HAMI: Cheapside Rd Ph2, Walpole, BU Replacement	**2023**	$ 35,871									
Southeast	**Div_16 - Hamilton**	Distribution Pipe	**Fail**	Dollar threshold	**733621**	HAMI: Main St E, Dunnville, BU Replacement	**2023**	$ 276,508									
Southeast	**Div_16 - Hamilton**	Distribution Pipe	**Fail**	Dollar threshold	**733622**	HAMI: Rainham Rd Ph1, Dunn, BU Replacement	**2023**	$ 1,271,437									
Southeast	**Div_16 - Hamilton**	Distribution Pipe	**Fail**	Dollar threshold	**733623**	HAMI: Rainham Rd Ph2, Dunn, BU Replacement	**2023**	$ 1,210,655									
Southeast	**Div_16 - Hamilton**	Distribution Pipe	**Fail**	Dollar threshold	**733626**	HAMI: Haldimand Rd 20, Walpole, BU Replacement	**2023**	$ 139,001									
Southeast	**Div_16 - Hamilton**	Distribution Pipe	**Fail**	Dollar threshold	**733627**	HAMI: Conc 3/Walpole Rd, Walpole, BU Replacement	**2023**	$ 109,856									
Southeast	**Div_16 - Hamilton**	Distribution Pipe	**Fail**	Dollar threshold	**733628**	HAMI: Rymer Rd, Sherbrooke, BU Replacement	**2023**	$ 127,791									
Southeast	**Div_16 - Hamilton**	Distribution Pipe	**Fail**	Dollar threshold	**733629**	HAMI: Victoria Ave E, Dunnville, BU Replacement	**2023**	$ 76,226									
Southeast	**Div_16 - Hamilton**	Distribution Pipe	**Fail**	Dollar threshold	**733631**	HAMI: North Shore/Hutchinson, Moulton, BU Replacement	**2024**	$ 34,604									
Southeast	**Div_16 - Hamilton**	Distribution Pipe	**Fail**	Dollar threshold	**733632**	HAMI: Port Maitland/Secord Rd, Dunnville, BU Replacement	**2023**	$ 107,614									
Southeast	**Div_16 - Hamilton**	Distribution Pipe	**Fail**	Dollar threshold	**733633**	HAMI: Robinson Rd, Canborough, BU Replacement	**2024**	$ 39,474									
Southeast	**Div_16 - Hamilton**	Distribution Pipe	**Fail**	Dollar threshold	**733634**	HAMI: Peacock Point, BU Replacement	**2025**	$ 78,836									
Southeast	**Div_16 - Hamilton**	Distribution Pipe	**Fail**	Dollar threshold	**733635**	HAMI: Diltz Rd, Moulton, BU Replacement	**2024**	$ 14,354									
Southeast	**Div_16 - Hamilton**	Distribution Pipe	**Fail**	Dollar threshold	**733642**	HAMI: Seneca Dr, Ancaster, BU Replacement	**2023**	$ 201,776									
Southeast	**Div_16 - Hamilton**	Distribution Pipe	**Fail**	Dollar threshold	**733643**	HAMI: Powerline Rd W, Ancaster, BU Replacement	**2023**	$ 11,210									
Southeast	**Div_16 - Hamilton**	Distribution Pipe	**Fail**	Dollar threshold	**733644**	HAMI: Woodbridge Rd, Hamilton, BU Replacement	**2023**	$ 13,452									
Southeast	**Div_16 - Hamilton**	Distribution Pipe	**Fail**	Dollar threshold	**733645**	HAMI: Rifle Range Rd, Hamilton, BU Replacement	**2023**	$ 248,110									
Southeast	**Div_16 - Hamilton**	Distribution Pipe	**Fail**	Dollar threshold	**733646**	HAMI: Glen/Dromore, Hamilton, BU Replacement	**2023**	$ 26,903									
Southeast	**Div_16 - Hamilton**	Distribution Pipe	**Fail**	Dollar threshold	**733647**	HAMI: Melvin Av, Hamilton, BU Replacement	**2023**	$ 44,839									
Southeast	**Div_16 - Hamilton**	Distribution Pipe	**Fail**	Dollar threshold	**733648**	HAMI: Hamilton East, BU Replacement	**2023**	$ 22,420									
Southeast	**Div_16 - Hamilton**	Distribution Pipe	**Fail**	Dollar threshold	**733649**	HAMI: Osler Dr @ Rail Trail, Dundas, BU Replacement	**2024**	$ 129,700									
Southeast	**Div_16 - Hamilton**	Distribution Pipe	**Fail**	Dollar threshold	**733650**	HAMI: Fleming Ave, Dundas, BU Replacement	**2024**	$ 108,425									
Southeast	**Div_16 - Hamilton**	Distribution Pipe	**Fail**	Dollar threshold	**733651**	HAMI: Mohawk Rd W, Hamilton, BU Replacement	**2024**	$ 26,145									
Southeast	**Div_16 - Hamilton**	Distribution Pipe	**Fail**	Dollar threshold	**733652**	HAMI: Hamilton Mountain East Ph2, Hamilton, BU Replacement	**2024**	$ 102,529									
Southeast	**Div_16 - Hamilton**	Distribution Pipe	**Fail**	Dollar threshold	**733654**	HAMI:Upper Gage Ave, Hamilton, BU Replacement	**2024**	$ 984,283									
Southeast	**Div_16 - Hamilton**	Distribution Pipe	**Fail**	Dollar threshold	**733655**	HAMI: Wellington St N /Wilson St, Hamilton, BU Replacement	**2024**	$ 35,885									
Southeast	**Div_16 - Hamilton**	Distribution Pipe	**Fail**	Dollar threshold	**733656**	HAMI:Barnaby St /Waterloo St, Hamilton, BU Replacement	**2024**	$ 64,594									
Southeast	**Div_16 - Hamilton**	Distribution Pipe	**Fail**	Dollar threshold	**733657**	HAMI: Hamilton Core, BU Replacement	**2024**	$ 41,524									
Southeast	**Div_16 - Hamilton**	Distribution Pipe	**Fail**	Dollar threshold	**733658**	HAMI: Stoney Creek, BU Replacement	**2024**	$ 78,435									
Southeast	**Div_16 - Hamilton**	Distribution Pipe	**Fail**	Dollar threshold	**733659**	HAMI: Burlington St E, Hamilton, BU Replacement	**2024**	$ 49,727									

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Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
Southeast	**Div_16 - Hamilton**	Distribution Pipe	**Pass**		**30396**	Div. 16 - Haldimand - Caledonia - Argyle St S - Hamilton - 1486	**2031**	$ 5,384,117	**Div. 16 - Haldimand - Caledonia - Argyle St. S. - Hamilton - 1486** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: There is significant overlap with the Bare and Unprotected (BU) Program. There is a reduction due to amount of main that will be replaced in 2022. The significant overlap is with the BU main project that was to be complete in 2021 and the proposed BU project on Peebles St. in 2022.**	Planned							
Southeast	**Div_16 - Hamilton**	Distribution Pipe	**Pass**		**30397**	Div. 16 - Haldimand - Canborough - Smithville Rd - Hamilton - 1488	**2031**	$ 3,812,570	**Div. 16 - Haldimand - Canborough - Smithville Rd. - Hamilton - 1488** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: Conservation authority permits are required.**	Planned							
Southeast	**Div_16 - Hamilton**	Distribution Pipe	**Pass**		**30398**	Div. 16 - Haldimand - Dunnville - Central Lane - Hamilton - 1361	**2030**	$ 4,399,494	**Div. 16 - Haldimand - Dunnville - Central Lane - Hamilton - 1361** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: There is significant overlap with the Bare and Unprotected (BU) Program. There is reduction due to amount of main that will be replaced in 2022. The significant overlap between three BU steel mains are to be replaced in 2022.**	Planned							
Southeast	**Div_16 - Hamilton**	Distribution Pipe	**Pass**		**30399**	Div. 16 - Haldimand - Fisherville - Erie Ave N 1 - Hamilton - 1728	**2029**	$ 3,307,362	**Div. 16 - Haldimand - Fisherville - Erie Ave N 1 - Hamilton - 1728** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: This project is best divided into two projects (Ph1 - Concession 5 Rd. and Ph2 - Erie Ave. N.).** **The estimate is to be adjusted after additional project is created. Conservation authority permits are required.**	Complete	**Fail**	NPS 2, cannot downsize or retire					
Southeast	**Div_16 - Hamilton**	Distribution Pipe	**Pass**		**30404**	Div. 16 - Hamilton - Centennial Pkwy N - Hamilton - 1747	**2029**	$ 3,353,705	**Div. 16 - Hamilton - Centennial Pkwy. N. - Hamilton - 1747** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: Include steel main at southeast of Limeridge Mall and the strip malls just south of Violet as it will be isolated steel.**	Planned							
Southeast	**Div_16 - Hamilton**	Distribution Pipe	**Pass**		**30405**	Div. 16 - Hamilton - Crooks St 1 - Hamilton - 1745	**2028**	$ 2,959,507	**Div. 16 - Hamilton - Crooks St. 1 - Hamilton - 1745** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
Southeast	**Div_16 - Hamilton**	Distribution Pipe	**Pass**		**30406**	Div. 16 - Hamilton - Crooks St 2 - Hamilton - 1746	**2031**	$ 2,717,545	**Div. 16 - Hamilton - Crooks St. 2 - Hamilton - 1746** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
Southeast	**Div_16 - Hamilton**	Distribution Pipe	**Pass**		**30413**	Div. 16 - Hamilton - Wentworth St S 2 - Hamilton - 1743	**2032**	$ 1,773,629	**Div. 16 - Hamilton - Wentworth St. S. 2 - Hamilton - 1743** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: Project will be split into two or three smaller projects with division at Main or King St. The estimate is low. The City is repaving the south portion of Wentworth Ave. S. near Cumberland.**	Planned							
Southeast	**Div_16 - Hamilton**	Distribution Pipe	**Pass**		**30414**	Div. 17 - Halton - Burlington - Guelph Line - Hamilton - 1429	**2032**	$ 7,289,615	**Div. 17 - Halton - Burlington - Guelph Line - Hamilton - 1429** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							

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Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
Southeast	**Div_16 - Hamilton**	Distribution Pipe	**Pass**		**30415**	Div. 17 - Halton - Oakville - 6th Line - Hamilton - 1413	**2032**	$ 4,985,105	**Div. 17 - Halton - Oakville - 6th Line - Hamilton - 1413** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
Southeast	**Div_16 - Hamilton**	Distribution Pipe	**Pass**		**48428**	HAMI: Dist-Repl-Contr-Mains Municipal*	**2020**	$ 42,151,611	**General: Projects in the relocation category are capital expenditures required to replace or relocate segments of pipeline in order to accommodate municipal infrastructure work. The cost sharing for this work is managed through the Franchise Agreements established with municipalities. A consultative approach is used between the municipality and EGI to avoid conflicts with municipal infrastructure early in the planning stage. If a conflict is unavoidable, pipeline assets are typically relocated or replaced.**	Planned							
Southeast	**Div_16 - Hamilton**	Distribution Pipe	**Pass**		**48442**	HAMI: Anodes*	**2020**	$ 15,547,449	**General: The anodes program within the corrosion program includes the required expenditure to install anodes in order to reduce the amount of down plant within EGI's 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.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Southeast	**Div_16 - Hamilton**	Distribution Pipe	**Pass**		**100849**	HAMI: NPS 10 Dominon Line Power Line Rd, Ancaster	**2026**	$ 2,746,489	**Issue/Concern/Opportunity: Pipeline Engineering has recommended that customer services no longer be installed directly off the 10" Dominion Line in the Ancaster/Flamborough. To address both the customer connection issue and to eliminate Punch-it tees, a station and IP main installation is proposed. Pipe size TBD.**	Planned							
Southeast	**Div_16 - Hamilton**	Distribution Pipe	**Pass**		**503350**	Moulton Replacement BU	**2025**	$ 18,528,994	**Issue/Concern/Opportunity: There is 5.6 km of NPS 8 Intermediate Pressure (IP) bare steel main to be replaced with NPS 8 IP Yellow Jacket (YJ) steel main between #1472 Hwy 3 to #2199 Hwy 3. The in-service date (ISD) is 2025.** **Justification: Replacement of NPS 8 IP bare steel with size-on-size NPS 8 IP YJ steel main for the 5.6 km segment is required.** **Assets: NPS 8 IP gas main between #1472 Hwy 3 to #2199 Hwy 3.** **Related Investments: Not applicable.**	Planned							
Southeast	**Div_16 - Hamilton**	Distribution Pipe	**Pass**		**733612**	NPS 12 Retrofit	**2024**	$ 2,594,375	**Project-Specific: External Corrosion Direct Assessment (ECDA) to In-Line Inspection (ILI) Program, supporting refinement of pipeline risk profile. Associated 2025 Operations and Maintenance (O&M) spend for ILI.** **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% Specified Minimum Yield Strength (SMYS). It includes installation costs for permanent 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 that are identified through the inspections.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Southeast	**Div_16 - Hamilton**	Distribution Stations	**Fail**	Dollar threshold	**101084**	HAMI: Cascade & Lanark Station Rebuild, Vault	**2025**	$ 1,286,534									
Southeast	**Div_16 - Hamilton**	Distribution Stations	**Fail**	Dollar threshold	**101090**	HAMI: Glancaster Hwy 6 & 20 Rd Station Rebuild, Frost Heave	**2023**	$ 523,123									
Southeast	**Div_16 - Hamilton**	Distribution Stations	**Fail**	Dollar threshold	**101094**	HAMI-Summit Trans Stn,	**2030**	$ 565,900									
Southeast	**Div_16 - Hamilton**	Distribution Stations	**Fail**	Dollar threshold	**101098**	HAMI - Six Nations	**2023**	$ 24,911									
Southeast	**Div_16 - Hamilton**	Distribution Stations	**Fail**	Dollar threshold	**101101**	HAMI - Diltz Rd IP North	**2026**	$ 521,289									
Southeast	**Div_16 - Hamilton**	Distribution Stations	**Fail**	Dollar threshold	**101103**	HAMI: Kenora & Bancroft Station Rebuild, Vault	**2023**	$ 622,765									
Southeast	**Div_16 - Hamilton**	Distribution Stations	**Fail**	Dollar threshold	**101126**	HAMI - Industrial St Vault Station	**2025**	$ 645,725									
Southeast	**Div_16 - Hamilton**	Distribution Stations	**Fail**	Dollar threshold	**101130**	HAMI - King St E Stn - Dundas	**2025**	$ 645,725									
Southeast	**Div_16 - Hamilton**	Distribution Stations	**Fail**	Dollar threshold	**101131**	HAMI - South Bend & Upper James Stn - Hamilton	**2025**	$ 645,725									
Southeast	**Div_16 - Hamilton**	Distribution Stations	**Fail**	Dollar threshold	**101132**	HAMI - Bancroft and Nash Vault Station	**2025**	$ 645,725									
Southeast	**Div_16 - Hamilton**	Distribution Stations	**Fail**	Dollar threshold	**101133**	HAMI - Ferrie and Wellington Vault Station	**2025**	$ 645,725									
Southeast	**Div_16 - Hamilton**	Distribution Stations	**Fail**	Dollar threshold	**101135**	HAMI - Clappison's Corners	**2025**	$ 645,725									
Southeast	**Div_16 - Hamilton**	Distribution Stations	**Fail**	Dollar threshold	**101140**	HAMI - US Steel Blast Furnace Atm Tank Replacement - Walpole	**2031**	$ 1,399,279									
Southeast	**Div_16 - Hamilton**	Distribution Stations	**Fail**	Dollar threshold	**103529**	HAMI: 12Z-301 Port Maitland Rymer Station, Haldimand, Heater Installation	**2024**	$ 640,809									
Southeast	**Div_16 - Hamilton**	Distribution Stations	**Fail**	Dollar threshold	**735023**	HAMI: Hamilton Gate 2, Noise Issues	**2027**	$ 1,345,483									
Southeast	**Div_16 - Hamilton**	Distribution Stations	**Fail**	Dollar threshold	**735037**	HAMI: Woodward bio gas, reinforcement	**2027**	$ 555,097									
Southeast	**Div_16 - Hamilton**	Distribution Stations	**Fail**	Dollar threshold	**735041**	HAMI: SE Corner of HWY 5 & 6, Maintenance	**2025**	$ 387,435									
Southeast	**Div_16 - Hamilton**	Distribution Stations	**Fail**	Dollar threshold	**735044**	HAMI: WATERDOWN NORTH DISTR'N STN, Boiler	**2026**	$ 1,303,223									
Southeast	**Div_16 - Hamilton**	Distribution Stations	**Fail**	Dollar threshold	**735047**	HAMI: VOORTMAN STN, heater Replacement	**2026**	$ 651,611									
Southeast	**Div_16 - Hamilton**	Distribution Stations	**Fail**	Dollar threshold	**735050**	HAMI: Empire Steel, Maintenance	**2030**	$ 141,475									
Southeast	**Div_16 - Hamilton**	Distribution Stations	**Fail**	Dollar threshold	**735051**	HAMI: Voith Fabrics, Maintenance	**2030**	$ 141,475									
Southeast	**Div_16 - Hamilton**	Distribution Stations	**Fail**	Dollar threshold	**735056**	HAMI: Mye Canada, Maintenance	**2030**	$ 70,737									
Southeast	**Div_16 - Hamilton**	Distribution Stations	**Fail**	Dollar threshold	**735057**	HAMI: Temple Canada, Maintenance	**2030**	$ 70,737									
Southeast	**Div_16 - Hamilton**	Distribution Stations	**Fail**	Dollar threshold	**735058**	HAMI: Birmingham and Burlington, Maintenance	**2028**	$ 550,470									
Southeast	**Div_16 - Hamilton**	Distribution Stations	**Fail**	Dollar threshold	**735065**	HAMI: Saint Gobain Abrasives, maintenance	**2030**	$ 282,950									
Southeast	**Div_16 - Hamilton**	Distribution Stations	**Pass**		**101086**	HAMI-Hamilton Gate 3	**2024**	$ 8,550,131	**Issue/Concern/Opportunity: The Hamilton Gate 3 Station needs a whole rebuild driven by integrity concerns. The station does not operate at full capacity. An early review of the heating system indicates that a redesign is required to improve the operation at the site.** **Furthermore, the property drains into the Boiler room depending on the amount of snowfall. The rebuild will address this water runoff concern.**	Planned							
Southeast	**Div_16 - Hamilton**	Distribution Stations	**Pass**		**101345**	HAMI - Hillcrest Station	**2027**	$ 2,081,614	**Issue/Concern/Opportunity: There are noise issues and old heater needs to be replaced on single feed station. Station is in high density area along the escarpment. It is a critical site and regulation should be buried. Scope is full rebuild.** **Assets: Station ID: 16X-218R** **Related Program: N/A**	Planned							

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Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
Southeast	**Div_16 - Hamilton**	Distribution Stations	**Pass**		**503271**	Hamilton/Halton PFM Compliance Program*		$ 843,392	**Issue/Concern/Opportunity: -PFMs that require a bypass will be rebuilt w/bypass to the new standard: oWhen they are due for a meter exchange and in the meter seal expiry year, provided that year is between 2022 and 2026. This will fall under the meter exchange budget and costs are not covered in this program. oIf the meter seal year is not between 2022 and 2026, the set will be rebuilt with a bypass the year after it is inspected. This will allow the technicians to identify which will require rebuilt at the time of inspection, and Sohan and I will be developing a process to get work orders generated for these rebuilds after the inspection. Also ensures that we focus our efforts on rebuilding active PFMs requiring rebuild. While I originally mentioned a proactive strategy to rebuild prior to the inspection year, we decided against that. -Assumption is that 50% of PFMs will need to be rebuilt. -Calculations are based on an estimate of $5500 per rebuild. As you know there is a significant swing depending on the pipe size, volume, existing set up (first stage cut, etc) that may influence this including the release of the new SEADs designs, that I have not seen yet.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Southeast	**Div_16 - Hamilton**	Distribution Stations	**Pass**		**735038**	HAMI: Hamilton Takeoff & Carlisle Gate, Rebuild	**2026**	$ 7,819,336	**Issue/Concern/Opportunity: The current station is experiencing frost heave due to a large pressure cut and the soil conditions that is leading to pipe movement. The odourant lines are kinked as a result of the station heaving. The existing heating system will be evaluated and possibly replaced with a CWT heater. The current pressure control devices are Control valves that have been experiencing reliability concerns and have required maintenance. The scope of this project is to rebuild with below-grade control valves. Assets: Related Investments: N/A**	Planned							
Southeast	**Div_16 - Hamilton**	Distribution Stations	**Pass**		**735043**	HAMI: Jarvis trans, full rebuild	**2026**	$ 6,516,114	**Station rebuild not required if Growth investment #30538 proceeds**	Planned							
Southeast	**Div_16 - Hamilton**	Distribution Stations	**Pass**		**735045**	HAMI: KIRKWALL/DOMINION, Full Rebuild	**2029**	$ 8,197,927	**Issue/Concern/Opportunity: Noise issues This site has received numerous noise complaints and odour from residents in the area. Constant bleeds on the control valves are causing the odour complaints. Consider Becker below grade ball valve station with no bleed pilots and DNGP for any needed flow control/pressure control. Fisher control valves are not a good option as they come with high O&M annual spend to operate and maintain. VALVE & PIPING: Most valves becoming difficult to turn even with greasing. Many position indicators on tops of valves have fallen off due to ongoing corrosion. FILTRATION: Filter decent shape – gas is dry and clean HEATING: System is in constant state of repair and boiler age is old. A lot of corrsosion on the glycol piping. There is not proper containement for the heat exchanger. Current system used all un-odourized gas inside. PRESSURE CONTROL: Control valves needs support from Lakeside Controls to perfrom annual Operations ODOURIZATION: Mois system (older vintage) room is very tight to get all assets inside the cabinet and room. Odourant cabinet in poor condition. No fire suppression system installed on odourant. TELEMETRY & ELECTRICAL: Back up generator in decent shape. Electrical panels in poor shape and not properly labelled. All building do not have any methane detection or CO detection in boiler rooms. MEASUREMENT . COMPLIANCE & OTHER Eng: Turbine meter is in decent shape and is used for process control only. Buildings are old and in declining condition. One is brick façade and the others are metal buildings. Fencing in decent shape. Gates droop in the winter and would be better to go to the sliding gate standard. Consider adding swipe card access to compound and buildings to meet corporate security standards to compound and buildings. There is not a containment area for any chemicals being stored on site. Ancaster Gate South is inside compound and is also in similar condition to Kirkwall-Dominion. There is supposed to be a pig launcher added to this site. Assets: 16W-606 Related Investments: N/A**	Planned							
Southeast	**Div_16 - Hamilton**	Distribution Stations	**Pass**		**735048**	HAMI :CALEDONIA TRANSMISSION STN, Rebuild	**2027**	$ 8,326,458	**Issue/Concern/Opportunity: VALVE & PIPING: Most valves becoming difficult to turn even with greasing. Many position indicators on tops of valves have fallen off due to ongoing corrosion. Lots of corrosion on piping and leaks on an orifice meter that cannot be repaired. Frost heave on the Mount Hope line. Paint of piping in entire site is in poor condition and lots of external rust. FILTRATION: Filter is getting replaced next month. If pigging at this site, a separator is needed. HEATING: System is old and poor shape. The heaters are oversized and there is some cracking on some of the older boilers. Because heaters do not run the correct length of time, some of the gas lines remain frosted on the second and third cut. Heat exchangers are not contained and boiler rooms only have angle iron containment on the floors. PRESSURE CONTROL: second station cut cannot keep up with demand to the Dunnville market. A pressure cuts are single regs and full capacity reliefs. Consider Becker buried ball valve station with no bleed pilots. ODOURIZATION: no odurant on site TELEMETRY & ELECTRICAL: Transmitters are old anolgue devices and situated to make ongoing testing and maintaining difficult. Electrical panels are old and not properly labbeled. There are no methane or CO detectors in boiler room. Should consider swipe card access to compound and buildings. Site does not have a back up generator. MEASUREMENT . COMPLIANCE & OTHER Eng: Orifice measurement has leaks and should be upgraded to a properly sized turbine meter. Measurement runs do not have any bypass piping. Site has an old storage building of metal construction. Need new storage building as this is a location where the Dunnville yard keeps materials and supplies in a remote location. There is not a contained area for any chemicals being stored on site. Need space from existing fencing to ajacent neighbors to keep vegetation controlled. Lots of vegetation coming up through fencing and gates are drooping, consider a new slide gate standard. Site access is off of highway 6 where traffic is at a high rate of speed (80 kph +) Consider possibility of accessing yard from rear laneway. Front fence line should be lined with Jersey barriers for compound protection. Snow plowing is a challenge at this location due to closeness to road and high rate of traffic speed. Existing compound does not have any crash bar man gates for egress. The heating system will be replaced during this project. Assets: 15X-401**	Planned							
Southeast	**Div_16 - Hamilton**	Growth	**Pass**		**30526**	SRP_Southeast_Ancaster_16W-601STN_Rebuild	**2024**	$ 181,990	**Build to higher capacity.**	Planned							
Southeast	**Div_16 - Hamilton**	Growth	**Pass**		**30538**	SRP_Southeast_Jarvis_12W-102STN_Rebuild	**2026**	$ 4,430,957	**Rebuild for increased capacity and lower pressure differential across station is required.**	Planned							
Southeast	**Div_16 - Hamilton**	Growth	**Pass**		**30539**	SRP_Southeast_Jarvis_12W-201STN_Rebuild	**2023**	$ 1,806,019	**Build to higher outlet pressure and higher capacity.**	Planned							
Southeast	**Div_16 - Hamilton**	Growth	**Pass**		**48427**	HAMI: Company Program - New Business - Scattered Mains - Contractor*	**2020**	$ 37,827,801	**Scattered Mains**	Planned							
Southeast	**Div_16 - Hamilton**	Growth	**Pass**		**500421**	HAMI: Company Program - Customer Connections*		$ 43,466,496	**Hamilton Customer Connections Program Items**	Planned							
Southeast	**Div_16 - Hamilton**	Growth	**Pass**		**736259**	Hamilton Industrial Reinforcement	**2025**	$ 132,907,739	**Issue/Concern/Opportunity :Reinforcement required to support changes to industrial demand in the area. Assets: Distribution Reinforcement Related Program: N/A**	Planned							
Southeast	**Div_16 - Hamilton**	Utilization	**Pass**		**48439**	HAMI: Meter & Regulator Inst Repl-Contractor	**2020**	$ 42,953,109	**Meter & Reg Install- Replacement**	Complete	**Fail**	See investment description, IRPAs not appliable					

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Southeast	**Div_16 - Hamilton**	Transmission Pipe & Underground Storage	**Pass**		**48654**	Dawn Parkway Expansion Project (Kirkwall-Hamilton NPS 48)	**2026**	$ 245,855,289	**Issue/Concern: In response to increased natural gas demand growth along the Dawn Parkway System, the Kirkwall to Hamilton Expansion has a forecast in-service date of November 1, 2026 and will provide reliable, secure, economic natural gas capacity to meet the growing design day demand of the Dawn Parkway Transmission system which serves both in- and ex-franchise markets.** **Assets:** **The Kirkwall-Hamilton Expansion Project consists of 10.2 km of NPS 48 pipeline from the Kirkwall Valve Site to the Hamilton Valve Site.** **Related Programs: N/A**	In Progress		Market side supply options to be asssed prior to LTC application					
Southwest	**Div_01 - Windsor**	Distribution Pipe	**Fail**	Dollar threshold	**30003**	Base Line 2 - Southwest - Windsor - 1347	**2031**	$ 1,702,262									
Southwest	**Div_01 - Windsor**	Distribution Pipe	**Fail**	Dollar threshold	**30007**	Callie Ave - Southwest - Windsor - 1377	**2027**	$ 1,441,870									
Southwest	**Div_01 - Windsor**	Distribution Pipe	**Fail**	Dollar threshold	**30008**	County Road 46 - Southwest - Windsor - 1352	**2029**	$ 1,680,921									
Southwest	**Div_01 - Windsor**	Distribution Pipe	**Fail**	Dollar threshold	**30014**	Elinor St - Southwest - Windsor - 1279	**2031**	$ 1,229,092									
Southwest	**Div_01 - Windsor**	Distribution Pipe	**Fail**	Dollar threshold	**30022**	Lanoue St - Southwest - Windsor - 1354	**2027**	$ 1,729,507									
Southwest	**Div_01 - Windsor**	Distribution Pipe	**Fail**	Dollar threshold	**30029**	Morand St 2 - Southwest - Windsor - 1657	**2029**	$ 1,407,792									
Southwest	**Div_01 - Windsor**	Distribution Pipe	**Fail**	Dollar threshold	**30034**	River View Line - Southwest - Windsor - 1381	**2029**	$ 360,917									
Southwest	**Div_01 - Windsor**	Distribution Pipe	**Fail**	Dollar threshold	**48289**	WIND: Dist-Repl-Contr-Mains Leakage*	**2020**	$ 7,382,794									
Southwest	**Div_01 - Windsor**	Distribution Pipe	**Fail**	Dollar threshold	**48290**	WIND: Dist-Repl-Contr-Services*	**2020**	$ 15,407,552									
Southwest	**Div_01 - Windsor**	Distribution Pipe	**Fail**	Dollar threshold	**48762**	WIND: Riverside Dr (Arlington to Kensington), Windsor, Replacement	**2027**	$ 380,935									
Southwest	**Div_01 - Windsor**	Distribution Pipe	**Fail**	Dollar threshold	**48779**	WIND: Maidstone Ave & Talbot St, Essex, Replacement	**2027**	$ 270,610									
Southwest	**Div_01 - Windsor**	Distribution Pipe	**Fail**	Dollar threshold	**48781**	WIND: Laird IP, Essex, Replacement	**2027**	$ 902,033									
Southwest	**Div_01 - Windsor**	Distribution Pipe	**Fail**	Dollar threshold	**48782**	WIND: Lacasse (St Denis to Tecumseh Rd E), Windsor, Replacement	**2023**	$ 204,890									
Southwest	**Div_01 - Windsor**	Distribution Pipe	**Fail**	Dollar threshold	**48796**	WIND: County Rd 27 Ph 1, Lakeshore, Replacement	**2028**	$ 1,513,792									
Southwest	**Div_01 - Windsor**	Distribution Pipe	**Fail**	Dollar threshold	**48851**	WIND: County Rd 31 & Essex County Rd 2, Lakeshore, Replacement	**2027**	$ 936,726									
Southwest	**Div_01 - Windsor**	Distribution Pipe	**Fail**	Dollar threshold	**48865**	WIND: County Rd 2 & Riverside Rd, Lakeshore, Replacement	**2027**	$ 242,855									
Southwest	**Div_01 - Windsor**	Distribution Pipe	**Fail**	Dollar threshold	**49007**	WIND: Somme Valve, Windsor, Replacement	**2025**	$ 128,499									
Southwest	**Div_01 - Windsor**	Distribution Pipe	**Fail**	Dollar threshold	**49714**	Bush Line Leakage Replacement Phase 1 & 2	**2031**	$ 1,816,264									
Southwest	**Div_01 - Windsor**	Distribution Pipe	**Fail**	Dollar threshold	**49719**	WIND: 2200 - 2204 County Rd 27, Lakeshore, Replacement	**2028**	$ 48,166									
Southwest	**Div_01 - Windsor**	Distribution Pipe	**Fail**	Dollar threshold	**49722**	WIND: Bertha Ave, Windsor, Replacement	**2027**	$ 575,913									
Southwest	**Div_01 - Windsor**	Distribution Pipe	**Fail**	Dollar threshold	**49729**	WIND: Devonshire Rd, Windsor, Replacement	**2027**	$ 346,242									
Southwest	**Div_01 - Windsor**	Distribution Pipe	**Fail**	Dollar threshold	**49732**	Fairview Line Replacement	**2031**	$ 1,277,541									
Southwest	**Div_01 - Windsor**	Distribution Pipe	**Fail**	Dollar threshold	**49734**	WIND: Glenwood Line & Port Rd, Chatham-Kent, Replacement	**2031**	$ 483,451									
Southwest	**Div_01 - Windsor**	Distribution Pipe	**Fail**	Dollar threshold	**49746**	WIND: Woodslee Ph 2, Lakeshore, Replacement	**2027**	$ 464,894									
Southwest	**Div_01 - Windsor**	Distribution Pipe	**Fail**	Dollar threshold	**49750**	WIND: Trenton St, Windsor, Replacement	**2031**	$ 489,048									
Southwest	**Div_01 - Windsor**	Distribution Pipe	**Fail**	Dollar threshold	**49752**	WIND: Tecumseh Rd E - Ph3, Windsor, Replacement	**2027**	$ 825,707									
Southwest	**Div_01 - Windsor**	Distribution Pipe	**Fail**	Dollar threshold	**49889**	WIND: Caille Ave, Lakeshore, Replacement	**2027**	$ 548,158									
Southwest	**Div_01 - Windsor**	Distribution Pipe	**Fail**	Dollar threshold	**101175**	WIND: Tecumseh Rd E - Ph4, Windsor, Replacement	**2023**	$ 466,451									
Southwest	**Div_01 - Windsor**	Distribution Pipe	**Fail**	Dollar threshold	**101177**	WIND: Tecumseh Rd E - Ph6, Windsor, Replacement	**2023**	$ 466,451									
Southwest	**Div_01 - Windsor**	Distribution Pipe	**Fail**	Dollar threshold	**101797**	WIND: Corrosion Rectifier Groundbed Program*	**2021**	$ 77,751									
Southwest	**Div_01 - Windsor**	Distribution Pipe	**Fail**	Dollar threshold	**102255**	WIND: Bayshore Dr, Leamington, Replacement	**2023**	$ 180,602									
Southwest	**Div_01 - Windsor**	Distribution Pipe	**Fail**	Dollar threshold	**102257**	WIND: County Rd 27 Ph 2, Lakeshore, Replacement	**2028**	$ 1,617,006									
Southwest	**Div_01 - Windsor**	Distribution Pipe	**Fail**	Dollar threshold	**102262**	WIND: Woodslee Ph 1, Lakeshore, Replacement	**2027**	$ 867,339									
Southwest	**Div_01 - Windsor**	Distribution Pipe	**Fail**	Dollar threshold	**501004**	WIND: PSLL Maintenance	**2023**	$ 503,194									
Southwest	**Div_01 - Windsor**	Distribution Pipe	**Pass**		**30001**	Aberdeen St - Southwest - Windsor - 1356	**2032**	$ 2,314,586	**Aberdeen St. - Southwest - Windsor - 1356** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
Southwest	**Div_01 - Windsor**	Distribution Pipe	**Pass**		**30002**	Base Line - Southwest - Windsor - 1623	**2032**	$ 2,648,940	**Base Line - Southwest - Windsor - 1623** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
Southwest	**Div_01 - Windsor**	Distribution Pipe	**Pass**		**30004**	Belle River Rd - Southwest - Windsor - 1366	**2032**	$ 1,809,150	**Belle River Rd. - Southwest - Windsor - 1366** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
Southwest	**Div_01 - Windsor**	Distribution Pipe	**Pass**		**30006**	Cabana Rd W - Southwest - Windsor - 1353	**2032**	$ 3,007,649	**Cabana Rd. W. - Southwest - Windsor - 1353** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							

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Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
Southwest	**Div_01 - Windsor**	Distribution Pipe	**Pass**		**30010**	Delaware Ave - Southwest - Windsor - 1364	**2028**	$ 2,461,467	**Delaware Ave. - Southwest - Windsor - 1364** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
Southwest	**Div_01 - Windsor**	Distribution Pipe	**Pass**		**30012**	Ducharme St - Southwest - Windsor - 1301	**2029**	$ 3,706,130	**Ducharme St - Southwest - Windsor - 1301** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
Southwest	**Div_01 - Windsor**	Distribution Pipe	**Pass**		**30013**	Edgar St - Southwest - Windsor - 1277	**2031**	$ 3,447,578	**Edgar St. - Southwest - Windsor - 1277** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
Southwest	**Div_01 - Windsor**	Distribution Pipe	**Pass**		**30015**	Elm Ave - Southwest - Windsor - 1295	**2030**	$ 4,253,853	**Elm Ave. - Southwest - Windsor - 1295** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
Southwest	**Div_01 - Windsor**	Distribution Pipe	**Pass**		**30016**	Giles Blvd E - Southwest - Windsor - 1282	**2030**	$ 2,204,266	**Giles Blvd. E. - Southwest - Windsor - 1282** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
Southwest	**Div_01 - Windsor**	Distribution Pipe	**Pass**		**30018**	Hanley Cres - Southwest - Windsor - 1350	**2030**	$ 2,822,041	**Hanley Cres. - Southwest - Windsor - 1350** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Complete	**Fail**	NPS 2, cannot downsize or retire					
Southwest	**Div_01 - Windsor**	Distribution Pipe	**Pass**		**30021**	Laird Ave - Southwest - Windsor - 1371	**2032**	$ 3,361,271	**Laird Ave. - Southwest - Windsor - 1371** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
Southwest	**Div_01 - Windsor**	Distribution Pipe	**Pass**		**30026**	Malden Rd 2 - Southwest - Windsor - 1660	**2032**	$ 2,819,824	**Malden Rd. 2 - Southwest - Windsor - 1660** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: This project will be split into a smaller project based on feedback from the region (Malden Rd. 1, 2, 3).**	Planned							
Southwest	**Div_01 - Windsor**	Distribution Pipe	**Pass**		**30031**	Pillette Rd - Southwest - Windsor - 1320	**2032**	$ 4,419,420	**Pillette Rd. - Southwest - Windsor - 1320** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
Southwest	**Div_01 - Windsor**	Distribution Pipe	**Pass**		**30032**	Randolph Ave - Southwest - Windsor - 1334	**2031**	$ 3,027,763	**Randolph Ave. - Southwest - Windsor - 1334** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
Southwest	**Div_01 - Windsor**	Distribution Pipe	**Pass**		**30033**	Rholaine Dr - Southwest - Windsor - 1299	**2028**	$ 2,183,224	**Rholaine Dr. - Southwest - Windsor - 1299** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							

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Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
Southwest	Div_01 - Windsor	Distribution Pipe	Pass		30035	Riverside Dr E - Southwest - Windsor - 1357	2032	$ 2,567,902	Riverside Dr. E. - Southwest - Windsor - 1357 Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.	Planned							
Southwest	Div_01 - Windsor	Distribution Pipe	Pass		30036	Rourke Line Rd - Southwest - Windsor - 1373	2031	$ 3,170,019	Rourke Line Rd. - Southwest - Windsor - 1373 Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.	Planned							
Southwest	Div_01 - Windsor	Distribution Pipe	Pass		30037	Spring Garden Rd - Southwest - Windsor - 1658	2028	$ 2,195,452	Spring Garden Rd. - Southwest - Windsor - 1658 Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization. Comments: Project is split into smaller projects based on feedback from region (Spring Garden Rd. and included in Malden Rd.).	Planned							
Southwest	Div_01 - Windsor	Distribution Pipe	Pass		30038	St Anne Blvd - Southwest - Windsor - 1319	2030	$ 2,221,991	St. Anne Blvd. - Southwest - Windsor - 1319 Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.	Planned							
Southwest	Div_01 - Windsor	Distribution Pipe	Pass		30039	Talbot Rd - Southwest - Windsor - 1369	2031	$ 3,120,988	Talbot Rd. - Southwest - Windsor - 1369 Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.	Planned							
Southwest	Div_01 - Windsor	Distribution Pipe	Pass		30042	Tecumseh Rd W 2 - Southwest - Windsor - 1492	2031	$ 3,772,556	Tecumseh Rd. W. 2 - Southwest - Windsor - 1492 Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.	Planned							
Southwest	Div_01 - Windsor	Distribution Pipe	Pass		30044	Walker Rd - Southwest - Windsor - 1333	2029	$ 3,711,443	Walker Rd. - Southwest - Windsor - 1333 Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.	Planned							
Southwest	Div_01 - Windsor	Distribution Pipe	Pass		48288	WIND: Dist-Repl-Contr-Mains Municipal*	2020	$ 71,550,345	General: Projects in the relocation category are capital expenditures required to replace or relocate segments of pipeline in order to accommodate municipal infrastructure work. The cost sharing for this work is managed through the Franchise Agreements established with municipalities. A consultative approach is used between the municipality and EGI to avoid conflicts with municipal infrastructure early in the planning stage. If a conflict is unavoidable, pipeline assets are typically relocated or replaced.	Planned							
Southwest	Div_01 - Windsor	Distribution Pipe	Pass		48302	WIND: Anodes*	2020	$ 8,143,100	General: The anodes program within the corrosion program includes the required expenditure to install anodes in order to reduce the amount of down plant within EGI's 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.	Complete	Fail	See investment description, IRPAs not appliable					
Southwest	Div_01 - Windsor	Distribution Pipe	Pass		48994	WIND: Laird & Centre MIP, Essex, Replacement	2028	$ 2,057,382	Replace 2,400 m of 2-inch/4-inch S DL protected main (35 kPa) with 250 m of 4-inch plastic main (420 kPa) and 3,850 m of 2-inch plastic main (420 kPa) on Laird Ave. and Centre St. in the Town of Essex. Abandon existing station and replace with new Lakeside pre-fab station. There are 150 services that will either need to be replaced or tied over.	Planned							
Southwest	Div_01 - Windsor	Distribution Pipe	Pass		49743	WIND: Riverside Aldyl A - Ph 1, Windsor, Replacement	2027	$ 2,151,002	This project will replace the approximately 1.1km of 1978 vintage Aldyl-A PE main along Riverside Drive in Windsor, from Bertha Street to Clover Drive. This main is known to be very brittle, has a total of 4 known C leaks, and many lined services. A portion of this 4" PE main is lined in the former 6" S CT main installed in 1968 that continues on either side of Riverside Drive, making maintenance and new service connections extremely difficult. There are approximately 18 services renewals required. Main to be replaced with 1100 m of 4" PE IP.	Planned							
Southwest	Div_01 - Windsor	Distribution Pipe	Pass		49747	WIND: Tecumseh Rd W, Windsor, Replacement	2028	$ 2,683,541	This job will replace 1,025 m of NPS 8 steel (S) Prior to Records (PTR) main on Tecumseh Rd. W. from Everts Ave. to Betts Ave. with 1,025 m of 8-inch S Yellow Jacket (YJ). This main is either too poor condition or laminated, and as a result cannot be welded on. In addition to weldability issues, several leaks have occurred over the last several years, which have all resulted in high capital expenditures to repair them. This main also requires many anodes try and maintain cathodic protection levels, all of which must be installed in wall-to-wall concrete. The most recent anodes were installed in the last two to three years meaning by 2025, new ones will need to be installed to replace them. This project will also include the renewal of 16 services.	Planned							
Southwest	Div_01 - Windsor	Distribution Pipe	Pass		49812	WIND: Oak St - Ph 2, Leamington, Replacement	2031	$ 2,091,921	Phase 2 will continue from the end point of the 2017 project, and replace the remaining 600 m of NPS 8 Prior to Records (PTR) pipe from Danforth to Oak Street station with 10-inch steel (S) Yellow Jacket (YJ). There will be 12 service renewals. There is one leak on this section of main.	Planned							
Southwest	Div_01 - Windsor	Distribution Pipe	Pass		49814	WIND: Tecumseh Rd E - Ph 2, Windsor, Replacement	2028	$ 2,993,180	Phase 2 will replace 1,000 m of Prior to Records (PTR) / DL protected NPS 8 Steel (S) main from 10490 to 11168 Tecumseh Rd. E. with 1,000 m of 8-inch S Yellow Jacket (YJ). There are a total of 14 services and 3 main tie-overs. This main is either in too poor condition or laminated, and as a result cannot be welded on. In addition to weldability issues, several leaks have occurred over the last several years which have all resulted in high capital expenditures to repair them. This area requires a substantial amount of anodes to keep it cathodically protected. This area also contains a large amount of growth and development for which the district currently cannot service due to the lacking pipe weldability.	Planned							
Southwest	Div_01 - Windsor	Distribution Pipe	Pass		49816	WIND: Mersea Rd 2 - Ph 2, Leamington, Replacement	2023	$ 1,690,807	This project is Phase 2 of a two-phase project to replace approximately 2,200 m of Coal Tar Wrap (C&W) (620 kPa) steel main along Mersea Rd. 2 (Oak St. Station to Deer Run Rd.). The second phase of this project will involve the replacement of 1,243 m of NPS 6 and 8 C&W (620 kPa) steel main with 1,200 m of 8-inch Steel (S) Yellow Jacket (YJ) gas main and 100 m of 2-inch S YJ. This project will also involve the renewal of 30 steel services.	Planned							

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Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
Southwest	**Div_01 - Windsor**	Distribution Pipe	**Pass**		**100688**	WIND: Riverside Aldyl A - Ph 2, Windsor, Replacement	**2028**	$ 3,027,585	**This project will replace the approximately 1.7km of 1978 vintage Aldyl-A PE main along Riverside Drive in Windsor, from Bertha Street to Clover Drive. This main is known to be very brittle, has a total of 4 known C leaks, and many lined services. A portion of this 4" PE main is lined in the former 6" S CT main installed in 1968 that continues on either side of Riverside Drive, making maintenance and new service connections extremely difficult. There are approximately 73 services renewals required. Main to be replaced with 700 m of 4" PE IP.**	Planned							
Southwest	**Div_01 - Windsor**	Distribution Pipe	**Pass**		**733732**	NPS 12, 10 Baldoon	**2024**	$ 4,672,494	**Project-Specific: External Corrosion Direct Assessment (ECDA) to In-Line Inspection (ILI) Program, supporting refinement of pipeline risk profile. Associated 2025 Operations and Maintenance (O&M) spend for ILI.** **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% Specified Minimum Yield Strength (SMYS). It includes installation costs for permanent 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 that are identified through the inspections.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Southwest	**Div_01 - Windsor**	Distribution Stations	**Fail**	Dollar threshold	**48291**	WIND: Plan(T)-Dist-Stn Measuring/Corrosion Stn*	**2020**	$ 4,591,035									
Southwest	**Div_01 - Windsor**	Distribution Stations	**Fail**	Dollar threshold	**101342**	WIND - 03B-102R County Rd 20 & Concession Rd 3 - Heater addition	**2023**	$ 215,817									
Southwest	**Div_01 - Windsor**	Distribution Stations	**Fail**	Dollar threshold	**101347**	WIND - 05B-401R Smith Ind Park - Station Rebuild with Heater	**2024**	$ 214,677									
Southwest	**Div_01 - Windsor**	Distribution Stations	**Fail**	Dollar threshold	**101357**	WIND - 06B-548I Chrysler Paint - Heater Replacement	**2024**	$ 206,069									
Southwest	**Div_01 - Windsor**	Distribution Stations	**Fail**	Dollar threshold	**101360**	WIND - 04B-401R Howard and Pike - Rebuild with Heater	**2026**	$ 305,412									
Southwest	**Div_01 - Windsor**	Distribution Stations	**Fail**	Dollar threshold	**101608**	WIND - 06D-401 Belle River Gate - Replace heater	**2031**	$ 624,761									
Southwest	**Div_01 - Windsor**	Distribution Stations	**Fail**	Dollar threshold	**101611**	WIND - 05A-304R Sprucewood IP - Replace heater	**2030**	$ 716,554									
Southwest	**Div_01 - Windsor**	Distribution Stations	**Fail**	Dollar threshold	**502698**	WIND - 03D-322C Leamington Hospital - rebuild	**2023**	$ 271,970									
Southwest	**Div_01 - Windsor**	Distribution Stations	**Fail**	Dollar threshold	**502700**	WIND - 06B-401 Grand Marais - reg repl & liquid tank	**2025**	$ 291,405									
Southwest	**Div_01 - Windsor**	Distribution Stations	**Fail**	Dollar threshold	**502701**	WIND - 04D-601R Albuna Station rebuild	**2030**	$ 1,173,124									
Southwest	**Div_01 - Windsor**	Distribution Stations	**Fail**	Dollar threshold	**502772**	WIND - 06B-314R Isabelle Place LP - rebuild	**2023**	$ 197,166									
Southwest	**Div_01 - Windsor**	Distribution Stations	**Fail**	Dollar threshold	**502773**	WIND - 06B-517R Ypres LP - rebuild	**2024**	$ 204,809									
Southwest	**Div_01 - Windsor**	Distribution Stations	**Fail**	Dollar threshold	**502774**	WIND - 03E-104C Thiessen Flower Shop - rebuild	**2028**	$ 265,880									
Southwest	**Div_01 - Windsor**	Distribution Stations	**Fail**	Dollar threshold	**502777**	WIND - 04A-302R Texas Rd	**2023**	$ 321,023									
Southwest	**Div_01 - Windsor**	Distribution Stations	**Fail**	Dollar threshold	**502950**	WIND: 06B-607I Ford/Nemak Station Rebuild	**2028**	$ 1,273,402									
Southwest	**Div_01 - Windsor**	Distribution Stations	**Fail**	Dollar threshold	**503331**	WIND - 06C-401 Manning Rd station rebuild	**2025**	$ 696,312									
Southwest	**Div_01 - Windsor**	Distribution Stations	**Fail**	Dollar threshold	**503333**	WIND - 06C-502 Patillo Rd station rebuild	**2024**	$ 739,649									
Southwest	**Div_01 - Windsor**	Distribution Stations	**Fail**	Dollar threshold	**734654**	WIND: 04E-438C Protolight Farms	**2026**	$ 311,740									
Southwest	**Div_01 - Windsor**	Distribution Stations	**Fail**	Dollar threshold	**734663**	WIND: 05B-205R Howard & Outer	**2029**	$ 300,135									
Southwest	**Div_01 - Windsor**	Distribution Stations	**Fail**	Dollar threshold	**734665**	WIND: 06C-602 Puce Transmission	**2027**	$ 225,447									
Southwest	**Div_01 - Windsor**	Distribution Stations	**Fail**	Dollar threshold	**734666**	WIND: 06A-605R Matchette & Prince	**2029**	$ 1,450,502									
Southwest	**Div_01 - Windsor**	Distribution Stations	**Fail**	Dollar threshold	**734667**	WIND: 06B-404 Bruce Ave	**2028**	$ 1,533,144									
Southwest	**Div_01 - Windsor**	Distribution Stations	**Fail**	Dollar threshold	**734673**	WIND: 06B-502 WALKER RD	**2032**	$ 694,756									
Southwest	**Div_01 - Windsor**	Distribution Stations	**Fail**	Dollar threshold	**735375**	WIND: 07H-402R Peter St Station LP	**2024**	$ 205,226									
Southwest	**Div_01 - Windsor**	Distribution Stations	**Fail**	Dollar threshold	**735378**	WIND: 06B-105R 540 Ouellette Dist		$ 99,642									
Southwest	**Div_01 - Windsor**	Distribution Stations	**Pass**		**101626**	WIND - 05A-203 LaSalle Boismier Ave - Heater replacement	**2025**	$ 3,099,480	**Issue/Concern/Opportunity: Heater controls are located within the hazardous area and are not rated to be within this zone. There is obsolete heating equipment; BS&B style heater that is on the risk register is to be replaced.** **Justification: Station needs to be rebuilt with new CWT 770. Potential requirement for additional land.** **Assets: 05A-203 LaSalle Boismier Ave.** **Related Investments: Not applicable.**	Planned							
Southwest	**Div_01 - Windsor**	Distribution Stations	**Pass**		**502697**	WIND - 05B-201 Windsor McGregor Line - rebuild	**2026**	$ 1,749,028	**Issue/Concern/Opportunity: Known corrosion issues are on risers.** **Justification: Rebuild station to eliminate potential for leak.** **Assets: 05B-201** **Related Investments: Not applicable.**	Planned							
Southwest	**Div_01 - Windsor**	Distribution Stations	**Pass**		**502699**	WIND - 05A-601 Front & Malden full rebuild	**2025**	$ 1,697,712	**Issue/Concern/Opportunity: Station freezes in winter so heater is required. Corrosion is significant on outlet riser. Land will be required to rebuild this station.** **Justification: Eliminate station freeze risk and remediate corrosion on riser.** **Assets: 05A-601** **Related Investments: Not applicable.**	Planned							
Southwest	**Div_01 - Windsor**	Distribution Stations	**Pass**		**503276**	Windsor/Chatham PFM Compliance Program*		$ 676,389	**Issue/Concern/Opportunity: -PFMs that require a bypass will be rebuilt w/bypass to the new standard:** **oWhen they are due for a meter exchange and in the meter seal expiry year, provided that year is between 2022 and 2026. This will fall under the meter exchange budget and costs are not covered in this program.** **oIf the meter seal year is not between 2022 and 2026, the set will be rebuilt with a bypass the year after it is inspected. This will allow the technicians to identify which will require rebuilt at the time of inspection, and Sohan and I will be developing a process to get work orders generated for these rebuilds after the inspection. Also ensures that we focus our efforts on rebuilding active PFMs requiring rebuild. While I originally mentioned a proactive strategy to rebuild prior to the inspection year, we decided against that.** **-Assumption is that 50% of PFMs will need to be rebuilt.** **-Calculations are based on an estimate of $5500 per rebuild. As you know there is a significant swing depending on the pipe size, volume, existing set up (first stage cut, etc) that may influence this including the release of the new SEADs designs, that I have not seen yet.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Southwest	**Div_01 - Windsor**	Distribution Stations	**Pass**		**503332**	WIND - 06B-403 California Ave station rebuild	**2024**	$ 4,101,179	**Issue/Concern/Opportunity: There are asbestos concerns. The converted NATCO heating system is out of date. There are hazardous area concerns. The maintenance of station is an ergonomics concern. The residential neighbourhood location not ideal. There is no containment for glycol.** **Justification: Station rebuild.** **Assets: 06B-403** **Related Investments: Not applicable.**	Planned							
Southwest	**Div_01 - Windsor**	Growth	**Pass**		**30549**	SRP_Southwest_Amherstburg_County Rd 20_Reinforcement_NPS4_1500m_420kPa	**2032**	$ 407,397	**Main extension connecting two 420 kPa pipes together in rural Amherstburg is required.**	Planned							
Southwest	**Div_01 - Windsor**	Growth	**Pass**		**30550**	SRP_Southwest_Blenheim_Industrial Ave_Reinforcement_NPS6_600m_420kPa	**2032**	$ 711,587	**Main reinforcement to tie larger mains together at the low point in Blenheim is required. Replace the existing 2-inch on the north side of Industrial Ave.**	Planned							
Southwest	**Div_01 - Windsor**	Growth	**Pass**		**30552**	SRP_Southwest_Essex_05B-401RSTN_Rebuild	**2023**	$ 1,126,974	**Increase station maximum sustainable from 275 kPa to 380 kPa.**	Planned							
Southwest	**Div_01 - Windsor**	Growth	**Pass**		**30561**	SRP_Southwest_Amherstburg_New STN & Reinforcement_NPS4_2200m_3450kPa	**2032**	$ 4,619,499	**Main extension to the west of the 3,450 kPa pipe and a new distribution station to feed into the 420 kPa network in rural Amherstburg is required.**	Planned							
Southwest	**Div_01 - Windsor**	Growth	**Pass**		**30574**	SRP_Southwest_Tecumseh_Manning_Reinforcement_NPS6_250m_420kPa	**2023**	$ 311,383	**Main extension to the south of Manning Rd. Station is required.**	Planned							

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Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
Southwest	**Div_01 - Windsor**	Growth	**Pass**		**30576**	SRP_Southwest_Windsor_05B-205RSTN_Rebuild	**2026**	$ 23,693	**Station is flowing over capacity.**	Planned							
Southwest	**Div_01 - Windsor**	Growth	**Pass**		**30577**	SRP_Southwest_Windsor_County Rd 42_Reinforcement_NPS6_3800m_420kPa	**2032**	$ 678,996	**Main extension to connect two existing 420 kPa pipes together south of the airport is required.**	Planned							
Southwest	**Div_01 - Windsor**	Growth	**Pass**		**30578**	SRP_Southwest_Windsor_Howard_Reinforcement_NPS6_1800m_420kPa	**2026**	$ 847,095	**Main extension and reinforcement to the south of Howard and Outer Station is required.**	Planned							
Southwest	**Div_01 - Windsor**	Growth	**Pass**		**48287**	WIND: Company Program - New Business - Scattered Mains - Contractor*	**2020**	$ 11,245,853	**Scattered Mains**	Planned							
Southwest	**Div_01 - Windsor**	Growth	**Pass**		**48306**	WIND: Generic Greenhouse Windsor*	**2020**	$ 81,077,243	**Customer Growth**	Planned							
Southwest	**Div_01 - Windsor**	Growth	**Pass**		**101359**	SRP_Southwest_Windsor_05A-201STN_Rebuild	**2023**	$ 2,138,292	**Issue/Concern/Opportunity: There is no station heat. The IP cut is at risk for freeze-off due to large pressure drop (3450kPa to 420kPa). Frost heave, fish-mouth supports, and ankle-level pipe are all concerns.** **Justification: Eliminate risk of regulator freeze-off and frost heave by adding a CWT 385, rebuild regulator runs (ankle-level and fish-mouth supports). Mercury remediation is needed.** **Assets: 05A-201 Turkey Creek** **Related Investments: 502777 - Texas Rd. - Valve MUST be fixed at Texas Rd. before work can begin.**	Planned							
Southwest	**Div_01 - Windsor**	Growth	**Pass**		**500415**	WIND: Company Program - Customer Connections*		$ 50,761,394	**Windsor Customer Connections Program Items**	Planned							
Southwest	**Div_01 - Windsor**	Growth	**Pass**		**736070**	WIND: LEAM-3 Panhandle Distribution Reinforcement - Essex Road 37 Reinforcement	**2026**	$ 1,432,721	**Issue/Concern/Opportunity: Greenhouse growth in the Windsor area continues. The Panhandle distribution network needs to be reinforced to allow for the continued industrial customer expansion. A Panhandle transmission reinforcement is also required to meet the demand of the region. LEAM-3 is a distribution system looping project with a station upgrade.** **Assets: 1,200 m of NPS 6 PE 420 kPa. Station Modification/Rebuild of 04E-501R - Mersea Rd 6/ Cty Rd 37.** **Related Program: Panhandle Regional Expansion Project 49758**	Planned							
Southwest	**Div_01 - Windsor**	Growth	**Pass**		**736071**	WIND: LEAM-4 Panhandle Distribution Reinforcement - Mersea Road 12 Reinforcement	**2031**	$ 1,960,382	**Issue/Concern/Opportunity: Greenhouse growth in the Windsor area continues. The Panhandle distribution network needs to be reinforced to allow for the continued industrial customer expansion. A Panhandle transmission reinforcement is also required to meet the demand of the region. LEAM-4 is a distribution system looping project:** **Assets: 1,600 m of NPS 6 ST 3450 kPa** **Related Program: Panhandle Regional Expansion Project 49758**	Planned							
Southwest	**Div_01 - Windsor**	Growth	**Pass**		**736073**	WIND: LEAM-7 Panhandle Distribution Reinforcement - Mersea Road 8 Reinforcement	**2023**	$ 1,270,441	**Issue/Concern/Opportunity: Greenhouse growth in the Windsor area continues. The Panhandle distribution network needs to be reinforced to allow for the continued industrial customer expansion. A Panhandle transmission reinforcement is also required to meet the demand of the region. LEAM-7 is a distribution system looping project:** **Assets: 1,300 m of NPS 6 ST, 3450 kPa** **Related Program: Panhandle Regional Expansion Project 49758**	Planned							
Southwest	**Div_01 - Windsor**	Growth	**Pass**		**736074**	WIND: Staples-1A Panhandle Distribution Reinforcement - Ontario Hwy 77 and Mersea Rd 7 Reinforcement	**2023**	$ 6,090,643	**Issue/Concern/Opportunity: Greenhouse growth in the Windsor area continues. The Panhandle distribution network needs to be reinforced to allow for the continued industrial customer expansion. A Panhandle transmission reinforcement is also required to meet the demand of the region.** **Staples-1A is a distribution system looping project which requires stations upgrades at Mersea Twp. Conc. 6** **Assets: 2,000 m of NPS 6 ST 3450 kPa. Mersea Twp Conc 6 Station (04E-401) modifications/rebuild** **Related Program: Panhandle Regional Expansion Project 49758**	Planned							
Southwest	**Div_01 - Windsor**	Growth	**Pass**		**736075**	WIND: Wheatley-1B - Panhandle Distribution Reinforcement - Wheatley Lateral Replacement and Reinforcement	**2024**	$ 21,106,551	**Risk/Concern/Opportunity:** **Greenhouse growth in the Windsor area continues. The Panhandle distribution network needs to be reinforced to allow for the continued industrial customer expansion. A Panhandle transmission reinforcement is also required to meet the demand of the region.** **Assets: Distribution Reinforcement** **Related Programs: N/A**	Planned							
Southwest	**Div_01 - Windsor**	Utilization	**Pass**		**48298**	WIND: Meter & Regulator Inst Repl-Contractor*	**2020**	$ 55,151,861	**Meter & Reg Install- Replacement**	Complete	**Fail**	See investment description, IRPAs not appliable					
Southwest	**Div_01 - Windsor**	Transmission Pipe & Underground Storage	**Pass**		**100086**	Panhandle Line Replacement	**2024**	$ 37,488,223	**Issue/Concern: EGI's Integrity Management team initiated work in 2019 to better understand the risk associated with the two NPS 12 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 internally inspected to check for the presence of the primary threat of internal corrosion; such inspection cannot be achieved given the configuration of the asset. 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 (Canada Energy Regulator-regulated crossing)** **Related Programs: Not applicable.**	Complete	**Fail**	LTC in progress					
Southwest	**Div_01 - Windsor**	Transmission Pipe & Underground Storage	**Pass**		**736923**	Panhandle Regional Expansion Project - Leamington Interconnect	**2024**	$ 69,934,844	**Issue/Concern/Opportunity:** **To provide reliable, secure, and affordable natural gas supply to meet the growth in Design Day demand of the Panhandle System,** **Assets:** **i) Leamington Interconnect : 12 km of 6040 kPag MOP NPS16 pipeline connecting the Leamington North Line, Leamington North Loop, Mersea Line and Kingsville East Line.** **ii. Leamington Interconnect Valve Sites: Three new valve sites with isolation valves are required to connect to each of the existing laterals (1. Leamington North Line and Leamington North Loop, 2. Mersea Line and 3. Kingsville East Line). Launcher/receiver facilities will be installed at location 1 and 3.** **Related Program:** **Not Applicable**	In Progress		Market side supply options to be assssed prior to LTC application					
Southwest	**Div_02 - Chatham**	Distribution Pipe	**Fail**	Dollar threshold	**48323**	CHAT: Dist-Repl-Contr-Services*		$ 244,088									
Southwest	**Div_02 - Chatham**	Distribution Pipe	**Fail**	Dollar threshold	**49721**	CHAT: Base Line, Wallaceburg, Replacement	**2025**	$ 1,097,733									
Southwest	**Div_02 - Chatham**	Distribution Pipe	**Fail**	Dollar threshold	**49856**	CHAT: St Clair St, Tilbury, Replacement	**2027**	$ 312,103									
Southwest	**Div_02 - Chatham**	Distribution Pipe	**Fail**	Dollar threshold	**49893**	CHAT: Water St & Talbot Trail, Chatham-Kent, Replacement	**2031**	$ 277,757									
Southwest	**Div_02 - Chatham**	Distribution Pipe	**Fail**	Dollar threshold	**101164**	CHAT: Ridge St, West Lorne, Replacement	**2023**	$ 49,198									
Southwest	**Div_02 - Chatham**	Distribution Pipe	**Fail**	Dollar threshold	**102251**	CHAT: Gordon St & Elm St, Chatham-Kent, Replacement	**2026**	$ 78,193									
Southwest	**Div_02 - Chatham**	Distribution Pipe	**Pass**		**49742**	CHAT: Ridgetown LP, Ridgetown, Replacement	**2027**	$ 1,908,147	**Replace approximately 1.9 km of NPS 4 low-pressure (LP) steel main in downtown Ridgetown with approximately 1.0 km of NPS 4 intermediate-pressure (IP) plastic main and 760 m of 2-inch IP plastic main. This IP system contains several leaks and is located mostly in wall-to-wall concrete (from Market Lane to Victoria Ave.). There are approximately 75 homes and businesses fed off of this system.**	Planned							

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Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
Southwest	Div_02 - Chatham	Distribution Pipe	Pass		49749	Tilbury South Line Replacement	2031	$ 2,863,693	General: 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.	Planned							
Southwest	Div_02 - Chatham	Distribution Pipe	Pass		49859	CHAT: Tweedsmuir LP, Chatham, Replacement	2027	$ 3,046,096	Replace 2,300 m of 4-inch steel, bare, protected gas main (2.5 kPa) with 4,300 m of 2-inch plastic gas main (420 kPa) in the Tweedsmuir subdivision in the Municipality of Chatham-Kent. There are 167 services that will need to be replaced.	Planned							
Southwest	Div_02 - Chatham	Distribution Pipe	Pass		733723	NPS 8 Dover Centre Retrofit		$ 2,065,337	Project-Specific: External Corrosion Direct Assessment (ECDA) to In-Line Inspection (ILI) Program, supporting refinement of pipeline risk profile. Associated 2026 Operations and Maintenance (O&M) spend for ILI. 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% Specified Minimum Yield Strength (SMYS). It includes installation costs for permanent 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 that are identified through the inspections.	Complete	Fail	See investment description, IRPAs not appliable					
Southwest	Div_02 - Chatham	Distribution Pipe	Pass		733733	NPS 10 Essex	2024	$ 4,031,684	Project-Specific: External Corrosion Direct Assessment (ECDA) to In-Line Inspection (ILI) Program, supporting refinement of pipeline risk profile. Associated 2025 Operations and Maintenance (O&M) spend for ILI. 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% Specified Minimum Yield Strength (SMYS). It includes installation costs for permanent 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 that are identified through the inspections.	Complete	Fail	See investment description, IRPAs not appliable					
Southwest	Div_02 - Chatham	Distribution Stations	Fail	Dollar threshold	101354	CHAT - 07H-601 Burke Line - Heater Replacement	2027	$ 975,725									
Southwest	Div_02 - Chatham	Distribution Stations	Fail	Dollar threshold	101610	CHAT - 07J-301 Ridgetown North Transmission - Replace heater	2024	$ 603,602									
Southwest	Div_02 - Chatham	Distribution Stations	Fail	Dollar threshold	502775	CHAT - 08H-302C Greenhill Produce - rebuild and heater addition	2023	$ 570,844									
Southwest	Div_02 - Chatham	Distribution Stations	Fail	Dollar threshold	502778	CHAT - 09G-502 Tupperville Trans - heater replacement	2026	$ 1,027,617									
Southwest	Div_02 - Chatham	Distribution Stations	Fail	Dollar threshold	734661	CHAT: 06J-103 Blenheim North Gate	2026	$ 285,332									
Southwest	Div_02 - Chatham	Distribution Stations	Fail	Dollar threshold	734669	CHAT: 07H-501 MAYNARD LINE	2030	$ 701,073									
Southwest	Div_02 - Chatham	Distribution Stations	Fail	Dollar threshold	734671	CHAT: 07K-409 MCKINLAY RD STATION	2031	$ 1,602,257									
Southwest	Div_02 - Chatham	Distribution Stations	Pass		101627	CHAT - 07G-201 Baldoon Transmission - Station Rebuild	2023	$ 996,424	Issue/Concern/Opportunity: Obsolete regulators cannot be serviced nor parts obtained to repair them; obsolete heating equipment contains 20,000 L of glycol and is on the risk register. Justification: Replace regulators and heaters. Assets: 07G-201 Baldoon Transmission Related Investments: Not applicable.	Planned							
Southwest	Div_02 - Chatham	Distribution Stations	Pass		503334	CHAT - 07G-601 Chatham North Gate	2026	$ 2,830,046	Issue/Concern/Opportunity: Converted BS&B and heat exchanger replacement is required. There have already been several environmental spills (glycol) as a result of condition failures from these converted heaters and is known on the risk register. Also, the condition of the heaters is creating risks around reliability and the ability to adequately provide heat. Justification: Potential for reliability issues with the safe and reliable delivery of natural gas. In addition, Possible glycol leaks from heating system equipment or piping inside building (indoor equipment typically includes boilers, pressure relief, glycol recirculation pumps, air extractors, instruments/controls, gauges, expansion tanks). Possible leaks from heating system equipment or piping located outside on station property (outdoor equipment typically includes the heat exchanger, overpressure burst disk, air extractors, instruments/controls, gauges, and atmospheric glycol expansion tank) Assets: 07G-601 Related Investments: Not applicable.	Planned							
Southwest	Div_02 - Chatham	Distribution Stations	Pass		734660	CHAT: 09F-501 Wallaceburg Baseline	2025	$ 2,047,659	Issue/Concern/Opportunity: There are concerns from Station Operations around the condition of the existing filter. If the filter cannot operate as per its intended use there is a potential to It is recommended to replace the complete station as there are reliability and integrity concerns. Justification: Replace filter (like for like). Assets: 09F-501 Related Investments: Not applicable.	Planned							
Southwest	Div_02 - Chatham	Growth	Pass		48320	CHAT: Company Program - New Business - Scattered Mains - Contractor*	2020	$ 2,303,369	Scattered Mains	Planned							
Southwest	Div_02 - Chatham	Growth	Pass		500416	CHAT: Company Program - Customer Connections*		$ 8,728,284	Chatham Customer Connections Program Items	Planned							
Southwest	Div_02 - Chatham	Utilization	Pass		48328	CHAT: Meter & Regulator Inst Repl-Company*	2020	$ 8,657,519	Meter & Reg Install- Replacement	Complete	Fail	See investment description, IRPAs not appliable					
Southwest	Div_02 - Chatham	Transmission Pipe & Underground Storage	Pass		49758	Panhandle Regional Expansion Project	2023	$ 219,431,846	Issue/Concern: To provide reliable, secure, and affordable natural gas supply to meet the growth in Design Day demand of the Panhandle System: Assets: i. Dawn Yard: 700 m of 8960 kPa MOP NPS42 station header is required to maintain the maximum sustainable pressure on design day. This header will also provide operational flexibility and security of supply to the Panhandle system. ii. Panhandle Take-off Station: The existing station will be modified to meet the new system capacity demand requiring measurement, odourization and regulation assets. iii. Dover Transmission Station: This existing regulating station will be modified to connect the new NPS 36 pipeline to the upstream system. Flow measurement equipment will also be added to the station. iv. Panhandle Loop : 19 km of 6040 kPag MOP NPS36 pipeline will parallel the NPS 20 from Dover Transmission station to a new valve site at Richardson Sideroad. v. Richardson Sideroad Valve Site: A new valve site is required at the end of the NPS 36 Panhandle loop to connect to the existing NPS20 mainline. Isolation valves and launcher/receiver facilities will be installed at this location. Related Program: Not applicable	In Progress		Market side supply options to be asssed prior to LTC application					

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Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
Southwest	**Div_02 - Chatham**	Transmission Pipe & Underground Storage	**Pass**		**735972**	PREP: NPS 36 looping to Comber Transmission	**2028**	$ 95,914,556	**Issue/Concern:** **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 as early as the 2028 to 2029 winter season (construction beginning in 2028). These facilities are incremental to the Panhandle Regional Expansion Project and timing is dependent on the Panhandle System demands.** **Assets:** **Install approximately 12 km of NPS 36 pipeline from Richardson sideroad, looping the existing Panhandle NPS 20 pipeline to Comber Transmission Station (05E-403).** **Related Program:** **Not applicable**	In Progress		Market side supply options to be assssed prior to LTC application					
Southwest	**Div_03 - Sarnia**	Distribution Pipe	**Fail**	Dollar threshold	**48336**	SARN: Dist-Repl-Contr-Services*		$ 87,271									
Southwest	**Div_03 - Sarnia**	Distribution Pipe	**Fail**	Dollar threshold	**48771**	SARN - Highway Dr and Lynwood Ave - Sarnia BU	**2024**	$ 369,106									
Southwest	**Div_03 - Sarnia**	Distribution Pipe	**Fail**	Dollar threshold	**48831**	SARN-Point Edward LP Leakage - Sarnia BU	**2024**	$ 922,765									
Southwest	**Div_03 - Sarnia**	Distribution Pipe	**Fail**	Dollar threshold	**48846**	SARN - Errol Rd E Leakage - Sarnia BU	**2023**	$ 1,006,388									
Southwest	**Div_03 - Sarnia**	Distribution Pipe	**Fail**	Dollar threshold	**48951**	SARN - Errol Rd W & Newell St. Leakage - Sarnia BU	**2023**	$ 848,206									
Southwest	**Div_03 - Sarnia**	Distribution Pipe	**Fail**	Dollar threshold	**101192**	SARN - Vidal & Cromwell Leakage - Sarnia BU	**2024**	$ 35,188									
Southwest	**Div_03 - Sarnia**	Distribution Pipe	**Fail**	Dollar threshold	**101193**	SARN - Lakeshore Rd. and Modeland Rd Leakage - Sarnia BU	**2024**	$ 752,647									
Southwest	**Div_03 - Sarnia**	Distribution Pipe	**Fail**	Dollar threshold	**101194**	SARN - Christina St at Highbury Pk Leakage - Sarnia BU	**2023**	$ 229,763									
Southwest	**Div_03 - Sarnia**	Distribution Pipe	**Fail**	Dollar threshold	**101210**	SARN - Smith Line Leakage - Sombra BU	**2024**	$ 142,452									
Southwest	**Div_03 - Sarnia**	Distribution Pipe	**Fail**	Dollar threshold	**101214**	SARN - Eastlawn Ave and Kember Ave Leakage - Sarnia BU	**2023**	$ 973,538									
Southwest	**Div_03 - Sarnia**	Distribution Pipe	**Fail**	Dollar threshold	**101295**	SARN -Kathleen Ave Leakage - Sarnia BU	**2023**	$ 69,712									
Southwest	**Div_03 - Sarnia**	Distribution Pipe	**Fail**	Dollar threshold	**502679**	SARN- Brigden Rd and Duncan St Leakage - Moore Twp	**2024**	$ 138,415									
Southwest	**Div_03 - Sarnia**	Distribution Pipe	**Fail**	Dollar threshold	**733836**	SARN - Oil Heritage Rd and Douglas Line Exposed Main	**2024**	$ 139,696									
Southwest	**Div_03 - Sarnia**	Distribution Pipe	**Fail**	Dollar threshold	**735710**	SARN- Zone St Leakage BU- Wyoming	**2024**	$ 96,890									
Southwest	**Div_03 - Sarnia**	Distribution Pipe	**Pass**		**1267**	Cogen Retrofit		$ 2,005,304	**Project-Specific: External Corrosion Direct Assessment (ECDA) to In-Line Inspection (ILI) Program, supporting refinement of pipeline risk profile. Associated 2024 Operations and Maintenance (O&M) spend for ILI.** **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 EGIs pipeline systems to ensure their continued safety and reliability. Most of the expenditure included in this category is for pipelines that operate above 30% Specified Minimum Yield Strength (SMYS). It includes installation costs for permanent 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 that are identified through the inspections.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Southwest	**Div_03 - Sarnia**	Distribution Pipe	**Pass**		**733720**	NPS 6 Retrofit	**2024**	$ 4,485,664	**Project-Specific: External Corrosion Direct Assessment (ECDA) to In-Line Inspection (ILI) Program, supporting refinement of pipeline risk profile. Associated 2025 Operations and Maintenance (O&M) spend for ILI.** **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% Specified Minimum Yield Strength (SMYS). It includes installation costs for permanent 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 that are identified through the inspections.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Southwest	**Div_03 - Sarnia**	Distribution Pipe	**Pass**		**733734**	NPS 6 Sarnia	**2024**	$ 2,750,066	**Project-Specific: External Corrosion Direct Assessment (ECDA) to In-Line Inspection (ILI) Program, supporting refinement of pipeline risk profile. Associated 2025 Operations and Maintenance (O&M) spend for ILI.** **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% Specified Minimum Yield Strength (SMYS). It includes installation costs for permanent 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 that are identified through the inspections.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Southwest	**Div_03 - Sarnia**	Distribution Stations	**Fail**	Dollar threshold	**734679**	SARN: 12F-201I Suncor Ethanol	**2029**	$ 396,233									
Southwest	**Div_03 - Sarnia**	Distribution Stations	**Fail**	Dollar threshold	**734680**	SARN: 13F-323R McPlank	**2029**	$ 642,171									
Southwest	**Div_03 - Sarnia**	Distribution Stations	**Fail**	Dollar threshold	**734685**	SARN: 13F-402 Shell Canada	**2029**	$ 512,370									
Southwest	**Div_03 - Sarnia**	Distribution Stations	**Fail**	Dollar threshold	**734693**	SARN: 11H-201R Oil Spring Reg Stn	**2026**	$ 221,548									
Southwest	**Div_03 - Sarnia**	Distribution Stations	**Fail**	Dollar threshold	**734696**	SARN: 14F-503R Point Edward Victoria and St. Clair Reg Stn	**2027**	$ 242,855									
Southwest	**Div_03 - Sarnia**	Distribution Stations	**Pass**		**48664**	CNG Stations - Project #1 - Dawn CNG	**2025**	$ 3,228,626	**Traditionally, fleet operators fuel their vehicles with gasoline or diesel. EGI promotes the use of natural gas to these customers as an alternate fuel source to provide a lower-cost and lower-emission fueling solution for vehicles such as garbage trucks, light duty vehicles, and transit buses. Business Development is responsible for the installation, maintenance, and the safe and continued operation of NGT stations assets for these customers. NGT stations differ in operation from distribution system stations as NGT stations use and store compressed natural gas (CNG) on site at up to 4000psi.** **EGD has two general categories for NGT station types: Large, Mobile and Utility NGT stations and Small NGT stations (also referred to as VRAs). Large, Mobile and Utility NGT stations are similar in operation and will be evaluated for condition in the same manner.**	Complete	**Fail**	See investment description, IRPAs not appliable for CNG					
Southwest	**Div_03 - Sarnia**	Distribution Stations	**Pass**		**734662**	SARN: 12F-106I Suncor Hydrogen/Air Products	**2029**	$ 2,418,389	**Issue/Concern/Opportunity: Heater age (per integrity) is a concern.** **Justification: Replace heater.** **Assets: 12F-106I** **Related Investments: Not applicable.**	Planned							
Southwest	**Div_03 - Sarnia**	Distribution Stations	**Pass**		**734670**	SARN: 13F-501 Sarnia Industrial	**2027**	$ 13,296,976	**Issue/Concern/Opportunity:** **The station is located on leased property that is limited in size and makes it difficult to install a required filter. In addition, the heater is past its average lifespan and there are other ergonomic concerns. There is an opportunity to merge the station with 13F-503 Churchill Rd Station and will be assessed during this project.** **Justification: Entire rebuild, potentially relocate.** **Assets: 13F-501** **Related Investments: 13F-503 may potentially be merged with this station in a relocation.**	Planned							

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Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
Southwest	**Div_03 - Sarnia**	Distribution Stations	**Pass**		**734676**	SARN: 13F-220R Vidal St	**2032**	$ 10,592,332	**Issue/Concern/Opportunity: 13F-220R is experiencing flooding due to its current location. The heater age is of concern and the control valves require an upgrade. Potential relocation is necessary due to building floods.** **Justification: Full rebuild is required.** **Assets:13F-220R** **Related Investments: Not applicable.**	Planned							
Southwest	**Div_03 - Sarnia**	Distribution Stations	**Pass**		**734683**	SARN: 12F-205 Novacor Moore Trans	**2028**	$ 3,719,374	**Issue/Concern/Opportunity: The heater short cycles and there are visible condition issues. The regulators' design is insufficient causing operational concerns and will be redesigned in this project to meet current standards.** **Justification: Complete rebuild is required.** **Assets: 12F-205** **Related Investments: Not applicable.**	Planned							
Southwest	**Div_03 - Sarnia**	Distribution Stations	**Pass**		**734684**	SARN: 13O-402 Westmount Gate	**2026**	$ 1,898,796	**Issue/Concern/Opportunity: Heater age (per integrity) is a concern.** **Loss of Heating System Function: Loss of the heating system function could result in two scenarios, (1) frost heave or (2) pressure control failure due to the freezing of station components. Frost heave occurs when the gas is cooled due to the pressure reduction and causes an upward swelling of soil around public or private property near the gas main. Freezing of station components such as creating large ice buildup around valves can prevent operation if gas isolation is required. This could result in the loss of pressure control and potentially lead to an overpressure or underpressure situation. 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.** **Justification: Replace heater.** **Assets: 13O-402** **Related Investments: Not applicable.**	Planned							
Southwest	**Div_03 - Sarnia**	Distribution Stations	**Pass**		**734697**	SARN: 13F-503 Churchill Rd. Trans Stn	**2027**	$ 6,997,195	**Issue/Concern/Opportunity: Aging heater is a concern related to the reliable and safe delivery of natural gas. 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.** **Loss of Heating System Function: Loss of the heating system function could result in two scenarios, (1) frost heave or (2) pressure control failure due to the freezing of station components. Frost heave occurs when the gas is cooled due to the pressure reduction and causes an upward swelling of soil around public or private property near the gas main. Freezing of station components such as creating large ice buildup around valves can prevent operation if gas isolation is required. This could result in the loss of pressure control and potentially lead to an overpressure or underpressure situation. 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.** **Justification: Heater replacement is required.** **Assets: 13F-503** **Related Investments: INV CODE 734670** **NOTE: This project could potentially be combined with Sarnia Industrial Station rebuild (under inv code noted above). If not, it will be a separate project for the heater replacement only. The execution and design team will evaluate the options closer to the execution year.**	Planned							
Southwest	**Div_03 - Sarnia**	Distribution Stations	**Pass**		**735540**	LOND - 12F-501 Payne Kimball Rebuild	**2026**	$ 12,445,777	**Issue/Concern/Opportunity: 12F-501 Payne Kimball has obsolete Jetstream pressure regulation equipment. Obsolete pressure control equipment cold increase the risk of an overpressure or under-pressure scenario. Due to the regulators being obsolete, maintenance may be impracticle. There is no meter bypass and there are ergonomic concerns.** **The piping and equipment layout presents ergonomic concerns and limits the ability for an employee to perform work and could lead to a potential LTI and has been risk ranked as a Medium risk.** **Justification: Complete rebuild is required.** **Assets: 9S-147H is similar to Mersea Rd 11 Trans with Odourant, backup generator.** **Related Investments: Not applicable.**	Planned							
Southwest	**Div_03 - Sarnia**	Growth	**Pass**		**48335**	SARN: Company Program - New Business - Scattered Mains - Contractor*	**2020**	$ 2,980,518	**Scattered Mains**	Planned							
Southwest	**Div_03 - Sarnia**	Growth	**Pass**		**500417**	SARN: Company Program - Customer Connections*		$ 8,617,147	**Sarnia Customer Connections Program Items**	Planned							
Southwest	**Div_04 - London**	Distribution Pipe	**Fail**	Dollar threshold	**30285**	Creston Ave - Southwest - London - 1734	**2031**	$ 1,653,463									
Southwest	**Div_04 - London**	Distribution Pipe	**Fail**	Dollar threshold	**30317**	Ross St - Southwest - London - 1560	**2032**	$ 1,593,599									
Southwest	**Div_04 - London**	Distribution Pipe	**Fail**	Dollar threshold	**30329**	Wortley Rd - Southwest - London - 1474	**2032**	$ 1,536,132									
Southwest	**Div_04 - London**	Distribution Pipe	**Fail**	Dollar threshold	**30442**	Stratford-Daly Ave with Birmingham to Worsley-1756	**2031**	$ 141,027									
Southwest	**Div_04 - London**	Distribution Pipe	**Fail**	Dollar threshold	**30443**	Stratford-Mercer St from Caledonia to Brittania-1757	**2029**	$ 359,080									
Southwest	**Div_04 - London**	Distribution Pipe	**Fail**	Dollar threshold	**30445**	Stratford-Mowat St from W. Gore to Brydges-1760	**2031**	$ 879,032									
Southwest	**Div_04 - London**	Distribution Pipe	**Fail**	Dollar threshold	**30464**	Downie St 3 - Southwest - London - 1808	**2029**	$ 1,667,750									
Southwest	**Div_04 - London**	Distribution Pipe	**Fail**	Dollar threshold	**48349**	LOND: Dist-Repl-Contr-Mains Leakage*	**2019**	$ 3,661,795									
Southwest	**Div_04 - London**	Distribution Pipe	**Fail**	Dollar threshold	**48350**	LOND: Dist-Repl-Contr-Services*	**2020**	$ 8,746,721									
Southwest	**Div_04 - London**	Distribution Pipe	**Fail**	Dollar threshold	**48372**	LOND - Waterloo St. BU - London	**2024**	$ 812,422									
Southwest	**Div_04 - London**	Distribution Pipe	**Fail**	Dollar threshold	**48759**	LOND - Talbot Line BU - Talbotville	**2024**	$ 224,283									
Southwest	**Div_04 - London**	Distribution Pipe	**Fail**	Dollar threshold	**48760**	LOND - St George & Talbot BU - St Thomas	**2024**	$ 92,277									
Southwest	**Div_04 - London**	Distribution Pipe	**Fail**	Dollar threshold	**48765**	LOND - Belgrave BU - London	**2024**	$ 192,243									
Southwest	**Div_04 - London**	Distribution Pipe	**Fail**	Dollar threshold	**48766**	LOND - Beverly St. BU - St Thomas	**2024**	$ 92,302									
Southwest	**Div_04 - London**	Distribution Pipe	**Fail**	Dollar threshold	**48797**	LOND - Kent & Central BU - London	**2024**	$ 275,548									
Southwest	**Div_04 - London**	Distribution Pipe	**Fail**	Dollar threshold	**48808**	LOND - Church & Water BU - Beachville	**2024**	$ 133,340									
Southwest	**Div_04 - London**	Distribution Pipe	**Fail**	Dollar threshold	**48811**	LOND - Jacqueline BU - London	**2023**	$ 1,353,505									
Southwest	**Div_04 - London**	Distribution Pipe	**Fail**	Dollar threshold	**48816**	LOND - St George St BU-Yarmouth	**2024**	$ 66,152									
Southwest	**Div_04 - London**	Distribution Pipe	**Fail**	Dollar threshold	**48826**	LOND- Whetter & Wellington BU - London	**2023**	$ 112,098									
Southwest	**Div_04 - London**	Distribution Pipe	**Fail**	Dollar threshold	**48828**	LOND-Sycamore & St Julien - London	**2024**	$ 198,651									
Southwest	**Div_04 - London**	Distribution Pipe	**Fail**	Dollar threshold	**48829**	LOND - Dalmage & Wood BU - London	**2024**	$ 192,243									
Southwest	**Div_04 - London**	Distribution Pipe	**Fail**	Dollar threshold	**48852**	LOND - St Neots & Ridout BU - London	**2024**	$ 106,672									
Southwest	**Div_04 - London**	Distribution Pipe	**Fail**	Dollar threshold	**48856**	LOND - PH 2 Stevenson & Brydges BU - London	**2023**	$ 493,230									
Southwest	**Div_04 - London**	Distribution Pipe	**Fail**	Dollar threshold	**48860**	LOND - Cathcart & Alma BU - Ingersoll	**2024**	$ 93,338									
Southwest	**Div_04 - London**	Distribution Pipe	**Fail**	Dollar threshold	**48873**	LOND - Seeley & Burslem BU - London	**2024**	$ 80,004									

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Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
Southwest	**Div_04 - London**	Distribution Pipe	**Fail**	Dollar threshold	**48874**	LOND - Elworthy & Edward BU - London	**2024**	$ 133,340									
Southwest	**Div_04 - London**	Distribution Pipe	**Fail**	Dollar threshold	**48875**	LOND - Malcolm Street BU - London	**2024**	$ 80,004									
Southwest	**Div_04 - London**	Distribution Pipe	**Fail**	Dollar threshold	**48876**	LOND - Summit & Oxford BU - London	**2024**	$ 115,346									
Southwest	**Div_04 - London**	Distribution Pipe	**Fail**	Dollar threshold	**48877**	LOND - Pall Mall & William BU - London	**2024**	$ 80,004									
Southwest	**Div_04 - London**	Distribution Pipe	**Fail**	Dollar threshold	**48878**	LOND - Grand & Wellington BU - London	**2024**	$ 106,672									
Southwest	**Div_04 - London**	Distribution Pipe	**Fail**	Dollar threshold	**48879**	LOND: - Elmwood Place BU - London	**2024**	$ 106,672									
Southwest	**Div_04 - London**	Distribution Pipe	**Fail**	Dollar threshold	**48880**	LOND - King & Adelaide BU - London	**2024**	$ 26,668									
Southwest	**Div_04 - London**	Distribution Pipe	**Fail**	Dollar threshold	**48881**	LOND - Riverside Dr & Wharncliffe BU - London	**2024**	$ 140,978									
Southwest	**Div_04 - London**	Distribution Pipe	**Fail**	Dollar threshold	**48882**	LOND - Tweedsmuir BU- London	**2024**	$ 66,670									
Southwest	**Div_04 - London**	Distribution Pipe	**Fail**	Dollar threshold	**48888**	LOND - Parkway & Huron BU - London	**2023**	$ 219,213									
Southwest	**Div_04 - London**	Distribution Pipe	**Fail**	Dollar threshold	**48891**	LOND - Fellner & Langmuir, Ashland & Wilton BU - London	**2024**	$ 945,193									
Southwest	**Div_04 - London**	Distribution Pipe	**Fail**	Dollar threshold	**48913**	LOND - Borden St. BU - London	**2024**	$ 89,713									
Southwest	**Div_04 - London**	Distribution Pipe	**Fail**	Dollar threshold	**48917**	LOND - Cheapside, Gammage & Linwood BU - London	**2023**	$ 986,460									
Southwest	**Div_04 - London**	Distribution Pipe	**Fail**	Dollar threshold	**48918**	LOND - Wharncliffe & Baseline BU - London	**2023**	$ 311,383									
Southwest	**Div_04 - London**	Distribution Pipe	**Fail**	Dollar threshold	**48919**	LOND - Putnam Rd. BU - London	**2024**	$ 93,338									
Southwest	**Div_04 - London**	Distribution Pipe	**Fail**	Dollar threshold	**48922**	LOND - Lexington & Wharncliffe BU - London	**2024**	$ 44,857									
Southwest	**Div_04 - London**	Distribution Pipe	**Fail**	Dollar threshold	**48923**	LOND - Tecumseh Ave BU - London	**2024**	$ 358,853									
Southwest	**Div_04 - London**	Distribution Pipe	**Fail**	Dollar threshold	**101543**	LOND - SCLAIR Pipe Replacement- Mount Brydges	**2031**	$ 979,495									
Southwest	**Div_04 - London**	Distribution Pipe	**Fail**	Dollar threshold	**101791**	LOND: Corrosion Rectifier Groundbed Program*	**2021**	$ 77,751									
Southwest	**Div_04 - London**	Distribution Pipe	**Fail**	Dollar threshold	**501003**	LOND: PSLL Maintenance	**2023**	$ 367,431									
Southwest	**Div_04 - London**	Distribution Pipe	**Fail**	Dollar threshold	**501665**	LOND - Murray St. BU - London	**2024**	$ 51,265									
Southwest	**Div_04 - London**	Distribution Pipe	**Fail**	Dollar threshold	**503339**	LOND - Wonham St Leakage, Ingersoll	**2023**	$ 78,954									
Southwest	**Div_04 - London**	Distribution Pipe	**Fail**	Dollar threshold	**733531**	LOND - Waterloo St at Horton St Leakage BU-London	**2024**	$ 232,120									
Southwest	**Div_04 - London**	Distribution Pipe	**Fail**	Dollar threshold	**734459**	LOND - 7113 to 7079 Longwoods Rd. - London	**2031**	$ 251,870									
Southwest	**Div_04 - London**	Distribution Pipe	**Fail**	Dollar threshold	**734460**	LOND - Breck Ave. & Eastgate Cres. - London	**2031**	$ 251,870									
Southwest	**Div_04 - London**	Distribution Pipe	**Pass**		**30275**	Adelaide St N - Southwest - London - 1527	**2027**	$ 3,803,719	**Adelaide St. N. - Southwest - London - 1527** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
Southwest	**Div_04 - London**	Distribution Pipe	**Pass**		**30277**	Base Line Rd E - Southwest - London - 1461	**2030**	$ 5,321,935	**Base Line Rd. E. - Southwest - London – 1461** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Complete	**Fail**	NPS 2, cannot downsize or retire					
Southwest	**Div_04 - London**	Distribution Pipe	**Pass**		**30278**	Briscoe St W - Southwest - London -1735	**2027**	$ 3,096,133	**Briscoe St. W. - Southwest - London - 1735** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
Southwest	**Div_04 - London**	Distribution Pipe	**Pass**		**30279**	Briscoe St W 2 - Southwest - London - 1736	**2027**	$ 3,520,899	**Briscoe St. W. 2 - Southwest - London - 1736** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
Southwest	**Div_04 - London**	Distribution Pipe	**Pass**		**30282**	Cheapside St - Southwest - London - 1453	**2030**	$ 2,974,341	**Cheapside St. - Southwest - London - 1453** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: Majority will be replaced with bare and unprotected (BU) in 2023.**	Planned							
Southwest	**Div_04 - London**	Distribution Pipe	**Pass**		**30283**	Cheapside St 2 - Southwest - London -1534	**2032**	$ 5,227,158	**Cheapside St. 2 - Southwest - London -1534** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: Some bare and unprotected – low-pressure (LP) was already replaced in 2021.**	Planned							

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Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
Southwest	**Div_04 - London**	Distribution Pipe	**Pass**		**30284**	Clarke Rd- Southwest - London - 1483	**2029**	$ 3,533,834	**Clarke Rd. - Southwest - London - 1483** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
Southwest	**Div_04 - London**	Distribution Pipe	**Pass**		**30290**	E Centre St - Southwest - London - 1412	**2032**	$ 2,605,399	**E. Centre St. - Southwest - London - 1412** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Complete	**Fail**	NPS 2, cannot downsize or retire					
Southwest	**Div_04 - London**	Distribution Pipe	**Pass**		**30291**	Elworthy Ave - Southwest - London - 1446	**2031**	$ 5,537,291	**Elworthy Ave. (moratorium until 2026) - Southwest - London - 1446** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: Majority of this project is scheduled for 2024. Lambeth had city work in 2021 and moratorium is until 2026. This project was updated to reflect moratorium until 2026.**	Planned							
Southwest	**Div_04 - London**	Distribution Pipe	**Pass**		**30292**	Emery St E - Southwest - London - 1472	**2032**	$ 5,024,156	**Emery St. E. (moratorium until 2026) - Southwest - London - 1472** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: City did reconstruction in 2020 and moratorium is until 2026. This project was updated to reflect moratorium until 2026.**	Planned							
Southwest	**Div_04 - London**	Distribution Pipe	**Pass**		**30294**	Front St - Southwest - London - 1393	**2031**	$ 2,375,054	**Front St. - Southwest - London - 1393** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Complete	**Fail**	NPS 2, cannot downsize or retire					
Southwest	**Div_04 - London**	Distribution Pipe	**Pass**		**30298**	Glenora Dr - Southwest - London - 1517	**2030**	$ 3,151,368	**Glenora Dr. - Southwest - London - 1517** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
Southwest	**Div_04 - London**	Distribution Pipe	**Pass**		**30300**	Greenwood Ave - Southwest - London - 1428	**2030**	$ 3,359,336	**Greenwood Ave. - Southwest - London - 1428** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
Southwest	**Div_04 - London**	Distribution Pipe	**Pass**		**30301**	Hamilton Rd - Southwest - London - 1408	**2031**	$ 3,833,564	**Hamilton Rd. - Southwest - London - 1408** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
Southwest	**Div_04 - London**	Distribution Pipe	**Pass**		**30312**	Mornington Ave - Southwest - London - 1531	**2031**	$ 8,694,188	**Mornington Ave. - Southwest - London - 1531** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: Some bare and unprotected (BU) and the 24-inch is on Strand s/b a separate project.**	Planned							
Southwest	**Div_04 - London**	Distribution Pipe	**Pass**		**30313**	Old Lakeshore Rd - Southwest - London - 1572	**2031**	$ 4,281,495	**Old Lakeshore Rd. - Southwest - London - 1572** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	In Progress							

* in the Investment Name indicates a program item. Program items are unique as they represent numerous projects grouped together and budgeted in advance. This results in forecast spend appearing larger than it would at the project level and it also impacts the in-service dates

Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
Southwest	Div_04 - London	Distribution Pipe	Pass		30316	Ridout St S - Southwest - London - 1470	2029	$ 2,840,207	Ridout St. S. - Southwest - London - 1470 Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.	Planned							
Southwest	Div_04 - London	Distribution Pipe	Pass		30319	Southdale Rd E - Southwest - London - 1434	2032	$ 8,236,025	Southdale Rd. E. - Southwest - London - 1434 Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.	Planned							
Southwest	Div_04 - London	Distribution Pipe	Pass		30325	Wellington Rd - Southwest - London - 1449	2029	$ 4,758,338	Wellington Rd. - Southwest - London - 1449 Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.	Planned							
Southwest	Div_04 - London	Distribution Pipe	Pass		30327	Wilton Grove Rd - Southwest - London - 1395	2032	$ 5,077,157	Wilton Grove Rd. - Southwest - London - 1395 Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.	Planned							
Southwest	Div_04 - London	Distribution Pipe	Pass		30328	Windsor Ave - Southwest - London - 1515	2029	$ 3,248,500	Windsor Ave. - Southwest - London - 1515 Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.	Planned							
Southwest	Div_04 - London	Distribution Pipe	Pass		30441	Stratford-Huron St-Matilda to Douglas Phase 2-1758	2030	$ 3,143,889	Stratford - Huron St. - Matilda to Douglas Phase 2 - 1758 Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.	Planned							
Southwest	Div_04 - London	Distribution Pipe	Pass		30461	Courthouse Sq - Southwest - London - 1802	2032	$ 1,860,014	Courthouse Sq. - Southwest - London - 1802 Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.	Planned							
Southwest	Div_04 - London	Distribution Pipe	Pass		30462	Downie St 1 - Southwest - London - 1806	2030	$ 3,536,340	Downie St. 1 - Southwest - London - 1806 Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.	Planned							
Southwest	Div_04 - London	Distribution Pipe	Pass		30465	Ontario Rd - Southwest - London - 1803	2032	$ 1,299,309	Ontario Rd. - Southwest - London - 1803 Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.	Planned							
Southwest	Div_04 - London	Distribution Pipe	Pass		30466	Queen St E - Southwest - London - 1804	2030	$ 2,662,891	Queen St. E. - Southwest - London - 1804 Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.	Planned							
Southwest	Div_04 - London	Distribution Pipe	Pass		48348	LOND: Dist-Repl-Contr-Mains Municipal*	2020	$ 45,104,908	General: Projects in the relocation category are capital expenditures required to replace or relocate segments of pipeline in order to accommodate municipal infrastructure work. The cost sharing for this work is managed through the Franchise Agreements established with municipalities. A consultative approach is used between the municipality and EGI to avoid conflicts with municipal infrastructure early in the planning stage. If a conflict is unavoidable, pipeline assets are typically relocated or replaced.	Planned							

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Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
Southwest	**Div_04 - London**	Distribution Pipe	**Pass**		**48364**	LOND: Anodes*	**2020**	$ 8,279,619	**General: The anodes program within the corrosion program includes the required expenditure to install anodes in order to reduce the amount of down plant within EGI's 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.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Southwest	**Div_04 - London**	Distribution Pipe	**Pass**		**100295**	NPS 8 Port Stanley Replacement	**2024**	$ 19,067,429	**Issue/Concern/Opportunity: The NPS 8 Port Stanley line is approximately 20 km of NPS 8 built in 1959, with unknown grade and wall thickness, bare and protected, and 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/each). 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 overgrown while other locations can be over 500 m 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. In 2000, 6.8 km of main were replaced due to corrosion and exposed pipe. In 2003, 230 meters were replaced 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: Port Stanley line is approximately 20 km of NPS 8 built in 1959. Related Programs: Not applicable.**	Planned							
Southwest	**Div_04 - London**	Distribution Pipe	**Pass**		**733736**	NPS 6 London	**2023**	$ 2,491,061	**Project-Specific: External Corrosion Direct Assessment (ECDA) to In-Line Inspection (ILI) Program, supporting refinement of pipeline risk profile. Associated 2024 Operations and Maintenance (O&M) spend for ILI. 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% Specified Minimum Yield Strength (SMYS). It includes installation costs for permanent 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 that are identified through the inspections.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Southwest	**Div_04 - London**	Distribution Pipe	**Pass**		**736302**	Wardsville Line - Southwest - London - 1797	**2028**	$ 13,046,196	**Wardsville Line - Southwest - London - 1797 Vintage steel exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (Vintage Steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization Site Specific: Recently completed a CIS/DCVG survey on it and it has many possible coating holidays. There was also a leak discovered in early December 2021. The pipeline has the same characteristics as the London Lines with respect to aerial crossings oThe design / construction method at the time of installation was to install aerial crossing over any drainage ditch or water crossing oCoating issues where the pipeline transitions out of the ground. The majority of the pipeline is within easement, travelling cross county for most of the running line; operationally the preference would be to relocate to the right of the way.**	Planned							
Southwest	**Div_04 - London**	Distribution Stations	**Fail**	Dollar threshold	**48376**	LOND - Mitchell Station Rebuild - London	**2028**	$ 427,165									
Southwest	**Div_04 - London**	Distribution Stations	**Fail**	Dollar threshold	**49861**	LOND: 14O-619I 3M Customer Station Rebuild; 528	**2030**	$ 466,867									
Southwest	**Div_04 - London**	Distribution Stations	**Fail**	Dollar threshold	**49862**	LOND: 14O-603I 3M Customer Station Rebuild	**2030**	$ 466,867									
Southwest	**Div_04 - London**	Distribution Stations	**Fail**	Dollar threshold	**100978**	LOND - 17K-601R Grand Bend Northgate	**2023**	$ 993,873									
Southwest	**Div_04 - London**	Distribution Stations	**Fail**	Dollar threshold	**100993**	19O-101 Dublin Gate	**2027**	$ 1,298,927									
Southwest	**Div_04 - London**	Distribution Stations	**Fail**	Dollar threshold	**100994**	15O-401R Bryanston Gate	**2023**	$ 1,167,062									
Southwest	**Div_04 - London**	Distribution Stations	**Fail**	Dollar threshold	**100998**	15R-604R Young & Peel LP Stn	**2026**	$ 175,935									
Southwest	**Div_04 - London**	Distribution Stations	**Fail**	Dollar threshold	**100999**	13O-113R Bathurse & Talbot	**2023**	$ 215,477									
Southwest	**Div_04 - London**	Distribution Stations	**Fail**	Dollar threshold	**733607**	LOND - 15N-671 Medway Creek Removal and Main Extension	**2023**	$ 74,732									
Southwest	**Div_04 - London**	Distribution Stations	**Fail**	Dollar threshold	**734658**	LOND: 13O-109R Edith and Mt. Pleasant	**2023**	$ 215,477									
Southwest	**Div_04 - London**	Distribution Stations	**Fail**	Dollar threshold	**734664**	LOND: 10M-503R Main and Shackleton	**2024**	$ 211,467									
Southwest	**Div_04 - London**	Distribution Stations	**Fail**	Dollar threshold	**734668**	LOND: 13O-210R Hale and Burslem	**2024**	$ 211,467									
Southwest	**Div_04 - London**	Distribution Stations	**Fail**	Dollar threshold	**734678**	LOND: 13O-212R Highbury and Brydges	**2024**	$ 211,467									
Southwest	**Div_04 - London**	Distribution Stations	**Fail**	Dollar threshold	**734681**	LOND: 14O-510R Curry and Oxford	**2024**	$ 211,467									
Southwest	**Div_04 - London**	Distribution Stations	**Fail**	Dollar threshold	**734687**	LOND: 19O-601 Mitchell Gate	**2027**	$ 520,404									
Southwest	**Div_04 - London**	Distribution Stations	**Fail**	Dollar threshold	**734688**	LOND: 13O-206R London Baseline Reg Station	**2025**	$ 1,350,857									
Southwest	**Div_04 - London**	Distribution Stations	**Fail**	Dollar threshold	**734690**	LOND: 17M-601 Centralia Stn	**2025**	$ 342,234									
Southwest	**Div_04 - London**	Distribution Stations	**Fail**	Dollar threshold	**734691**	LOND: 15R-608R Walter and Fyfe Reg Stn	**2025**	$ 219,547									
Southwest	**Div_04 - London**	Distribution Stations	**Fail**	Dollar threshold	**734692**	LOND: 13O-123R Napier and Blackfriars Reg Stn	**2025**	$ 219,547									
Southwest	**Div_04 - London**	Distribution Stations	**Fail**	Dollar threshold	**734694**	LOND: 11O-306R Wellington and Fifth Reg Stn	**2026**	$ 221,548									
Southwest	**Div_04 - London**	Distribution Stations	**Fail**	Dollar threshold	**735272**	LOND: 13O-401 White Oaks	**2028**	$ 646,802									
Southwest	**Div_04 - London**	Distribution Stations	**Fail**	Dollar threshold	**735275**	LOND: 16O-301 St. Mary's Gate	**2028**	$ 646,802									
Southwest	**Div_04 - London**	Distribution Stations	**Fail**	Dollar threshold	**735276**	LOND: 15J-401 Forest Gate Transmission Station	**2025**	$ 374,521									
Southwest	**Div_04 - London**	Distribution Stations	**Fail**	Timing	**500438**	10O-501 Port Stanley Gate Reg Corrosion Repair	**2023**	$ 3,113,826				Within 3 years, supply side not applicable					
Southwest	**Div_04 - London**	Distribution Stations	**Pass**		**100996**	13P-101R Sovereign & Gore	**2024**	$ 1,867,318	**Issue/Concern/Opportunity: There is frost heave impacting the road outside of station. Stations where a highpressure reduction occurs can be subject to freezing of 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. Ice buildup is visible on the downstream components and the station assembly is misaligned due to heaving. Consequence on a 35DD ION: The southeast corner of London will have low pressures and areas dropping below minimums. Approximate number of customers Lost: 3,600+, Major customers lost: Kaiser Aluminum and Accuride Assets: Tembec Spruce Falls SMS (41402004) Related Investments: N/A**	Planned							

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Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
Southwest	**Div_04 - London**	Distribution Stations	**Pass**		**503272**	London/Sarnia PFM Compliance Program*		$ 1,031,773	**Issue/Concern/Opportunity: -PFMs that require a bypass will be rebuilt w/bypass to the new standard: oWhen they are due for a meter exchange and in the meter seal expiry year, provided that year is between 2022 and 2026. This will fall under the meter exchange budget and costs are not covered in this program. oIf the meter seal year is not between 2022 and 2026, the set will be rebuilt with a bypass the year after it is inspected. This will allow the technicians to identify which will require rebuilt at the time of inspection, and Sohan and I will be developing a process to get work orders generated for these rebuilds after the inspection. Also ensures that we focus our efforts on rebuilding active PFMs requiring rebuild. While I originally mentioned a proactive strategy to rebuild prior to the inspection year, we decided against that. -Assumption is that 50% of PFMs will need to be rebuilt. -Calculations are based on an estimate of $5500 per rebuild. As you know there is a significant swing depending on the pipe size, volume, existing set up (first stage cut, etc) that may influence this including the release of the new SEADs designs, that I have not seen yet.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Southwest	**Div_04 - London**	Distribution Stations	**Pass**		**734674**	LOND: 14O-503R Highbury and Cheapside Dist Stn	**2024**	$ 9,583,267	**Issue/Concern/Opportunity: The station has obsolete regulators (Grove regulators) where replacement parts are no longer available. In the event of a failure, no replacement parts are available. In addition, the station is receving liquids and only has a dry gas filter installed. There are concerns with the potential of liquids entering the pressure control equipment and potentially impacting the performance of these assets. There is a single bypass valve that does not meet the current design standards and could impact manual bypass operations. The site has a large pressure drop and heat is required to prevent heaving. Justification: Complete station rebuild is required. Assets: 14O-503R Related Investments: Not applicable.**	Planned							
Southwest	**Div_04 - London**	Distribution Stations	**Pass**		**734689**	LOND: 14R-104 Beachville Domtar Trans Stn	**2024**	$ 8,458,681	**Issue/Concern/Opportunity: The station is equipped with a dry gas filter and is currently receiving liquids at the inlet of the station without the ability to remove the liquids. There are concerns that if liquid gets to the pressure control equipment, there may not be reliable pressure control and may lead to other operational issues. The heating system is obsolete and has the potential to leak glycol to the ground. There is a significant volume of glycol in the heating system (i.e., > 5,000 L) that could lead to environmental concerns if released from the existing aging heating system. This investment is to replace the heating system, the filter and remove underground insulation. Justification: Complete rebuild is required. Assets: 14R-104 Related Program: Not applicable**	Planned							
Southwest	**Div_04 - London**	Distribution Stations	**Pass**		**734695**	LOND: 15Q-603 C C Trans Stn	**2027**	$ 4,635,770	**Issue/Concern/Opportunity: Heater age (per integrity) is a concern. Loss of Heating System Function: Loss of the heating system function could result in two scenarios, (1) frost heave or (2) pressure control failure due to the freezing of station components. Frost heave occurs when the gas is cooled due to the pressure reduction and causes an upward swelling of soil around public or private property near the gas main. Freezing of station components such as creating large ice buildup around valves can prevent operation if gas isolation is required. This could result in the loss of pressure control and potentially lead to an overpressure or underpressure situation. 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. FIMP will assess the site closer to execution to determine if additional components require replacement. Assets: 15Q-603 Related Investments: Not applicable.**	Planned							
Southwest	**Div_04 - London**	Distribution Stations	**Pass**		**735155**	LOND: 21L-201 Goderich Gate	**2028**	$ 2,005,087	**Issue/Concern/Opportunity: Heater age (per integrity) is a concern. Justification: Replace heater. Assets: 21L-201 Related Investments: Not applicable.**	Planned							
Southwest	**Div_04 - London**	Growth	**Pass**		**30551**	SRP_Southwest_Embro_15Q-301STN_Rebuild	**2023**	$ 504,896	**Station flows over capacity in Winter 2023.**	Planned							
Southwest	**Div_04 - London**	Growth	**Pass**		**30553**	SRP_Southwest_Forest_Townsend Line_Reinforcement_NPS6_4500m_3450kPa	**2031**	$ 6,156,826	**Maintain system minimum inlets to downstream constraints.**	Planned							
Southwest	**Div_04 - London**	Growth	**Pass**		**30554**	SRP_Southwest_Innerkip_16S-503STN_Rebuild	**2029**	$ 1,373,566	**Rebuild Innerkip Transmission Station to a capacity of 2,470 m3/hr and set pressure to 1,860 kPa so downstream stations meet their inlet pressures.**	Planned							
Southwest	**Div_04 - London**	Growth	**Pass**		**30555**	SRP_Southwest_Kettle Point_Ravenswood Line_Reinforcement_NPS4_2000m_3450kPa	**2027**	$ 2,359,163	**Maintain system minimum inlets to downstream constraints.**	Planned							
Southwest	**Div_04 - London**	Growth	**Pass**		**30556**	SRP_Southwest_London_13O-402STN_Rebuild	**2023**	$ 1,758,068	**Westmount station is flowing over capacity, currently without System Reinforcement Plan (SRP) growth.**	Planned							
Southwest	**Div_04 - London**	Growth	**Pass**		**30557**	SRP_Southwest_London_Bradley Ave_Reinforcement_NPS6_500m_420kPa	**2031**	$ 322,329	**A 6-inch reinforcement to maintain system minimum pressures is required.**	Planned							
Southwest	**Div_04 - London**	Growth	**Pass**		**30558**	SRP_Southwest_London_Byron Baseline_Reinforcement_NPS8_700m_420kPa	**2023**	$ 1,684,679	**There is 8-inch main out of Byron station required to increase pressures north.**	Planned							
Southwest	**Div_04 - London**	Growth	**Pass**		**30559**	SRP_Southwest_Mt. Brydges_12M-303RSTN_Rebuild	**2023**	$ 1,316,573	**Station is flowing over capacity. Minimum inlet can increase.**	Planned							
Southwest	**Div_04 - London**	Growth	**Pass**		**30560**	SRP_Southwest_Sarnia_New STN & Reinforcement_NPS6_1600m_420kPa	**2032**	$ 1,176,280	**A new distribution station off of the existing 1,210 kPa system and a main extension to tie into the 420 kPa system north of Sarnia along the water is required.**	In Progress							
Southwest	**Div_04 - London**	Growth	**Pass**		**30563**	SRP_Southwest_Bluewater_New STN & Reinforcement_NPS4_7200m_3450kPa	**2025**	$ 8,833,102	**Transmission pipe from Bluewater to a new station in Saint Joseph is required (verify Maximum Operating Pressure [MOP] of 550 kPa).**	In Progress							
Southwest	**Div_04 - London**	Growth	**Pass**		**30564**	SRP_Southwest_Oil Springs_11H-201RSTN_Rebuild	**2023**	$ 192,797	**Station is flowing over capacity at Oil Springs.**	Planned							
Southwest	**Div_04 - London**	Growth	**Pass**		**30565**	SRP_Southwest_Port Stanley_George Street_Reinforcement_NPS4_300m_420kPa	**2029**	$ 149,246	**A 4-inch looping is required to increase pressures downstream.**	Planned							
Southwest	**Div_04 - London**	Growth	**Pass**		**30566**	SRP_Southwest_Woodstock_Reinforcement & Reinforcement_NPS6_8200m_1900kPa	**2024**	$ 11,662,726	**New 6-inch ST (1,900 kPa) line from Beachville Lateral to existing 6-inch main. New station is to be constructed on ether end of new main.**	Planned							
Southwest	**Div_04 - London**	Growth	**Pass**		**30568**	SRP_Southwest_Sarnia_13F-324RSTN_Rebuild	**2023**	$ 51,724	**Station is flowing over capacity.**	Planned							
Southwest	**Div_04 - London**	Growth	**Pass**		**30569**	SRP_Southwest_St. Marys_Church Street_Reinforcement_NPS6_100m_420kPa	**2032**	$ 59,950	**Trout Creek River Crossing**	Planned							
Southwest	**Div_04 - London**	Growth	**Pass**		**30570**	SRP_Southwest_St. Marys_Glass Street_Reinforcement_NPS4_650m_420kPa	**2030**	$ 108,562	**New business reinforcement on new street in St Mary's is required.**	Planned							
Southwest	**Div_04 - London**	Growth	**Pass**		**30571**	SRP_Southwest_Stratford_18Q-501RSTN_Rebuild	**2030**	$ 1,422,251	**Increase maximum sustainable and increase capacity.**	Planned							
Southwest	**Div_04 - London**	Growth	**Pass**		**30572**	SRP_Southwest_Talbotville_11O-173STN_Rebuild	**2023**	$ 385,230	**Talbotville South Station will be flowing over capacity in Winter 2023. Station upgrades are required. New station should have an outlet of 380 kPa instead of the existing 275 kPa.**	Planned							

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Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
Southwest	**Div_04 - London**	Growth	**Pass**		**30573**	SRP_Southwest_Talbotville_Talbotville Gore Rd_Reinforcement_NPS4_500m_420kPa	**2030**	$ 222,928	**A 4-inch main reinforcement is required to maintain system minimum pressures.**	Planned							
Southwest	**Div_04 - London**	Growth	**Pass**		**30575**	SRP_Southwest_Thamesford_Thorndale Road_Reinforcement_NPS4_570m_420kPa	**2031**	$ 246,999	**Reinforcement is needed to maintain system minimum pressures in Thamesford.**	Planned							
Southwest	**Div_04 - London**	Growth	**Pass**		**30579**	SRP_Southwest_Wonderland_New STN & MOP Upgrade	**2026**	$ 13,032,227	**A Maximum Operating Pressure (MOP) upgrade of the 6,160 listed pipe out of Hensall Transmission, upgrade to the inlets of existing stations along this line to 6,160 kPa inlet MOP, and installation of new station near Lucan to regulate from 6,160 to 3,450 is required.**	Planned							
Southwest	**Div_04 - London**	Growth	**Pass**		**30580**	SRP_Southwest_Woodstock_Oxford Road 17_Reinforcement_NPS6_1100m_420kPa	**2023**	$ 502,457	**A 6-inch loop is required to bump up pressures in north Woodstock.**	Planned							
Southwest	**Div_04 - London**	Growth	**Pass**		**48347**	LOND: Company Program - New Business - Scattered Mains - Contractor*	**2020**	$ 38,833,990	**Scattered Mains**	Planned							
Southwest	**Div_04 - London**	Growth	**Pass**		**49805**	SRP_Southwest_Hensall Trans_14N-302STN_Rebuild	**2023**	$ 8,220,500	**A rebuild of the Hensall Transmission Station (14N-302) is required to increase capacity and maximum sustainable outlet pressure to defer reinforcement of the Hensall Transmission System by three years.** **This project was assumed to be completed in 2023 for the community expansion projects on this system. This could affect its ability to be optimized or deferred.** **Grain dryer customer inquiries on this system are the driver for this project.**	Planned							
Southwest	**Div_04 - London**	Growth	**Pass**		**500418**	LOND: Company Program - Customer Connections*		$ 108,963,296	**London Customer Connections Program Items**	Planned							
Southwest	**Div_04 - London**	Growth	**Pass**		**734672**	SRP_Southwest_Kerwood_12K-301STN_Rebuild	**2026**	$ 3,905,901	**Issue/Concern/Opportunity: Heater, building, dry gas filter, general condition, heater past average lifespan (per integrity), and capacity increase are all concerns. A complete rebuild is required.** **Distribution Optimization Engineering (DOE) has also called out a need for additional capacity and a new station design will add this.** **Assets: 12K-301** **Related Programs: Not applicable**	Planned							
Southwest	**Div_04 - London**	Utilization	**Pass**		**48361**	LOND: Meter & Regulator Inst Repl-Contractor*	**2020**	$ 89,253,271	**Meter & Reg Install- Replacement**	Complete	**Fail**	See investment description, IRPAs not appliable					
Southwest	**Div_04 - London**	Transmission Pipe & Underground Storage	**Pass**		**100699**	Dawn Parkway Expansion Project (Dawn-Enniskillen NPS 48)	**2029**	$ 339,185,787	**Issue/Concern: In response to increased natural gas demand growth along the Dawn Parkway System, the Kirkwall to Hamilton Expansion has a forecast in-service date of 2029 to 2030 and will provide reliable, secure, economic natural gas capacity to meet the growing design day demand of the Dawn Parkway Transmission system which serves both in- and ex-franchise markets.** **These facilities are incremental to the Kirkwall to Hamilton Expansion (INV 48654) and timing is dependent on the Dawn Parkway System demands.** **Assets:** **Install approximately 17.2 km of NPS 48 internally-coated pipeline from Dawn Compressor Station (10G-301) to Enniskillen Valve Site (11H-301V) on the Dawn Parkway System.** **Related Program:** **Not applicable**	In Progress		Market side supply options to be assssed prior to LTC application					
Southwest	**Div_16 - Hamilton**	Distribution Pipe	**Pass**		**733738**	NPS 8 Port Elgin South Hampton	**2025**	$ 5,422,124	**Project-Specific: External Corrosion Direct Assessment (ECDA) to In-Line Inspection (ILI) Program, supporting refinement of pipeline risk profile. Associated 2026 Operations and Maintenance (O&M) spend for ILI.** **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% Specified Minimum Yield Strength (SMYS). It includes installation costs for permanent 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 that are identified through the inspections**	Complete	**Fail**	See investment description, IRPAs not appliable					
STO - EGD	**70 - Storage**	Compression Stations	**Fail**	Dollar threshold	**3380**	SCOR:61004 Top End-O/H incl. Cam Upgrade		$ 24,938									
STO - EGD	**70 - Storage**	Compression Stations	**Fail**	Dollar threshold	**4145**	SCOR:132FCV033-Upgrade	**2023**	$ 311,728									
STO - EGD	**70 - Storage**	Compression Stations	**Fail**	Dollar threshold	**8469**	SCOR:iNET-Upgrade	**2027**	$ 90,325									
STO - EGD	**70 - Storage**	Compression Stations	**Fail**	Dollar threshold	**8624**	SCHT:Control Room-Expand	**2023**	$ 1,296,788									
STO - EGD	**70 - Storage**	Compression Stations	**Fail**	Dollar threshold	**8626**	SCHT:Controls-Upgrade	**2027**	$ 90,325									
STO - EGD	**70 - Storage**	Compression Stations	**Fail**	Dollar threshold	**8627**	SCHT:XV,ESV,Actuators-O/H*	**2032**	$ 1,795,921									
STO - EGD	**70 - Storage**	Compression Stations	**Fail**	Dollar threshold	**8628**	SCHT:Dehy Automatn-Upgrade	**2023**	$ 405,246									
STO - EGD	**70 - Storage**	Compression Stations	**Fail**	Dollar threshold	**8631**	SSOM:Instr,Controls-Upgrade*	**2029**	$ 875,746									
STO - EGD	**70 - Storage**	Compression Stations	**Fail**	Dollar threshold	**8632**	SSOM:GAC Fan-Upgrade	**2025**	$ 505,898									
STO - EGD	**70 - Storage**	Compression Stations	**Fail**	Dollar threshold	**8633**	SSOM:Transfr Switch-Replace	**2027**	$ 270,974									
STO - EGD	**70 - Storage**	Compression Stations	**Fail**	Dollar threshold	**8652**	LM:MS Wireless Mesh-Install*	**2024**	$ 493,016									
STO - EGD	**70 - Storage**	Compression Stations	**Fail**	Dollar threshold	**8687**	SSOM:61001-Engine Minor	**2023**	$ 162,099									
STO - EGD	**70 - Storage**	Compression Stations	**Fail**	Dollar threshold	**8688**	SSOM:61002-Engine minor	**2023**	$ 162,099									
STO - EGD	**70 - Storage**	Compression Stations	**Fail**	Dollar threshold	**8841**	SCOR:HMI Hi Perf Grafx-Install	**2024**	$ 1,150,371									
STO - EGD	**70 - Storage**	Compression Stations	**Fail**	Dollar threshold	**8842**	MM:HMI Hi Perf Grafx-Replace 2026	**2026**	$ 1,182,733									
STO - EGD	**70 - Storage**	Compression Stations	**Fail**	Dollar threshold	**8843**	MM:HMI Hi Perf Grafx-Replace 2029	**2029**	$ 1,250,105									
STO - EGD	**70 - Storage**	Compression Stations	**Fail**	Dollar threshold	**8844**	SCOR:HMI PCs-Replace*	**2023**	$ 81,049									
STO - EGD	**70 - Storage**	Compression Stations	**Fail**	Dollar threshold	**8845**	SCOR:HMI PCs-Replace*	**2025**	$ 83,963									
STO - EGD	**70 - Storage**	Compression Stations	**Fail**	Dollar threshold	**8846**	SCOR:HMI PCs-Replace*	**2028**	$ 89,555									
STO - EGD	**70 - Storage**	Compression Stations	**Fail**	Dollar threshold	**8848**	SCOR:810001 IDC-Replace 2026	**2026**	$ 849,991									
STO - EGD	**70 - Storage**	Compression Stations	**Fail**	Dollar threshold	**8849**	SCOR:810001 IDC-Replace 2031	**2031**	$ 906,625									

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Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	8850	SSOM:810001 IDC-Replace	2028	$ 551,108									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	8851	SSOM:UPS-replace 2023	2023	$ 162,098									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	8852	SSOM:UPS-replace 2027	2027	$ 180,649									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	9023	SM:FIMP Recommend'ns-Implement 2023*	2023	$ 62,346									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	9024	SM:FIMP Recommend'ns-Implement 2024*	2024	$ 64,069									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	9025	SM:FIMP Recommend'ns-Implement 2025*	2025	$ 64,587									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	9026	SM:FIMP Recommend'ns-Implement 2026*	2026	$ 65,384									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	9027	SM:FIMP Recommend'ns-Implement 2027*	2027	$ 69,481									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	9028	SM:FIMP Recommend'ns-Implement 2028*	2028	$ 68,889									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	9063	SM:SCADA-Annual Upgrade 2023*	2023	$ 68,580									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	9064	SM:SCADA-Annual Upgrade 2024*	2024	$ 70,476									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	9065	SM:SCADA-Annual Upgrade 2025*	2025	$ 71,045									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	9066	SM:SCADA-Annual Upgrade 2026*	2026	$ 71,922									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	9081	SM:SCADA-Annual Upgrade 2027*	2027	$ 76,429									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	9082	SM:SCADA-Annual Upgrade 2028*	2028	$ 75,777									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	10030	SCHT:UPS-replace	2026	$ 34,000									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	12863	SCOR:Unit Pre-Heat-Convrt 12863	2024	$ 352,379									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	12864	SCOR:Unit Pre-Heat-Convrt 12864	2024	$ 352,379									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	12865	SCOR:Unit Pre-Heat-Convrt 2025	2025	$ 355,227									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	12869	SM:Obsolete Elec-Replace 2023*	2023	$ 68,580									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	12870	SM:Obsolete Elec-Replace 2024*	2024	$ 70,476									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	12871	SM:Obsolete Elec-Replace 2025*	2025	$ 71,046									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	12872	SM:Obsolete Elec-Replace 2026*	2026	$ 71,922									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	12873	SM:Obsolete Elec-Replace 2027*	2027	$ 76,429									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	12878	SM:Obsolete Instr-Replace 2023*	2023	$ 68,580									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	12879	SM:Obsolete Instr-Replace 2024*	2024	$ 70,476									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	12880	SM:Obsolete Instr-Replace 2025*	2025	$ 71,046									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	12881	SM:Obsolete Instr-Replace 2026*	2026	$ 71,922									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	12882	SM:Obsolete Instr-Replace 2027*	2027	$ 76,429									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	12913	SCOR:62008 Comp-Major O/H	2031	$ 453,312									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	12914	SCOR:62009 Comp-Major O/H	2030	$ 458,505									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	12915	SCOR:62010 Comp-Major O/H	2029	$ 445,158									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	12916	SCOR:62011 Comp-Major O/H	2028	$ 447,775									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	12919	SCOR:61004 Bottom End-O/H	2023	$ 124,691									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	12922	SCOR:620xx Cyl Liner-Replace*	2023	$ 327,987									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	12923	SCOR:620xx Cyl Liner-Replace*	2025	$ 365,523									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	12928	SCOR:64109 JWC-Replace	2028	$ 738,160									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	12929	SCOR:641 JWC VFD-Install	2029	$ 852,740									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	12940	SCOR:Obsolete Mech-Replace 2023*	2023	$ 118,456									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	12947	SM:100MOV Yard Valve-Replace 2024*	2024	$ 503,464									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	12951	SCOR:100MOV Yard Valve-Replace 2023*	2023	$ 979,845									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	12952	SM:100MOV Yard Valve-Replace 2027*	2027	$ 545,991									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	12953	SM:100MOV Yard Valve-Replace 2025*	2025	$ 507,534									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	12954	SM:100MOV Yard Valve-Replace 2026*	2026	$ 513,799									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	12955	SM:100MOV Yard Valve-Replace 2029*	2029	$ 538,174									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	12975	SCOR:622xx Bypass Valve-Upgrade 2026	2026	$ 345,227									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	12977	SCOR:622xx Bypass Valve-Upgrade 2023	2023	$ 329,185									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	12978	SCOR:622xx Bypass Valve-Upgrade 2024	2024	$ 338,284									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	12979	SCOR:622xx Bypass Valve-Upgrade 2025	2025	$ 170,509									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	12984	SCOR:622xx Unit Vlv-Heat Trace*	2023	$ 16,459									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	12985	SCOR:622xx Unit Vlv-Heat Trace*	2024	$ 16,914									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	12986	SCOR:622xx Unit Vlv-Heat Trace*	2025	$ 17,051									

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Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	12992	SCOR:352 Gas Detectrs-Replace 2023	2023	$ 16,459									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	12993	SCOR:352 Gas Detectrs-Replace 2024	2024	$ 16,914									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	12994	SCOR:352 Gas Detectrs-Replace 2025	2025	$ 17,051									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	12995	SCOR:352 Gas Detectrs-Replace 2026	2026	$ 17,261									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	12996	SCOR:352 Gas Detectrs-Replace 2027	2027	$ 18,343									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	12997	SCOR:530 FCV Positioners-Replace 2024	2024	$ 169,142									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	12998	SCOR:530 FCV Positioners-Replace 2025	2025	$ 170,509									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	12999	SCOR:530 FIT186-Upgrade	2025	$ 83,963									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	13000	SCOR:530 FIT126-Upgrade	2026	$ 84,999									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	13002	SCOR:520 MCC2 Starter-Upgrade	2025	$ 83,963									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	13003	SCOR:820 APU PLC-Upgrade	2026	$ 172,613									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	13023	SCOR:810 Touch Screens-Rplace	2028	$ 27,280									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	13026	SCOR:810 Touch Screens-Rplace*	2023	$ 24,689									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	13027	SCOR:810 Touch Screens-Rplace*	2024	$ 25,371									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	13028	SCOR:810 Touch Screens-Rplace*	2025	$ 25,576									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	13029	SCOR:810 Touch Screens-Rplace*	2026	$ 25,892									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	13030	SCOR:810 Touch Screens-Rplace*	2027	$ 27,514									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	13031	SCOR:MCC3 APU PLC-Rplace	2025	$ 596,782									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	17109	SCOR:Obsolete Mech-Replace 2024*	2024	$ 121,731									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	17117	SCOR:Obsolete Mech-Replace 2025*	2025	$ 122,715									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	17118	SCOR:Obsolete Mech-Replace 2026*	2026	$ 124,229									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	17119	SCOR:Obsolete Mech-Replace 2027*	2027	$ 132,013									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	17120	SCOR:Obsolete Mech-Replace 2028*	2028	$ 130,888									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	17204	SM:100MOV Yard Valve-Replace 2028*	2028	$ 541,338									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	17205	SCOR:352 Gas Detectrs-Replace 2028	2028	$ 18,186									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	17206	SM:Obsolete Instr-Replace 2028*	2028	$ 75,777									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	17208	SM:Obsolete Elec-Replace 2028*	2028	$ 75,777									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	19388	SCOR:525 UPS-Replace*	2028	$ 181,865									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	19389	SCOR:810002 IDC-Replace	2028	$ 909,328									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	40007	SCOR:60004 Oil Filtr-Replace	2023	$ 211,352									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	40008	SCOR:65004 AUX Pump-Replace	2023	$ 23,691									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	100870	SCOR:62211-PSV-010-Decrease Set Pressure	2023	$ 716,123									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	100969	SCOR:65004 Forced Lube-Replace	2023	$ 37,407									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	101606	SCOR:352 Gas Detectrs-Replace 2029	2029	$ 18,080									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	101607	SCOR:352 Gas Detectrs-Replace 2030	2030	$ 18,622									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	101863	SCOR:Obsolete Mech-Replace 2029*	2029	$ 130,123									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	101864	SCOR:Obsolete Mech-Replace 2030*	2030	$ 134,024									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	101865	SM:Obsolete Elec-Replace 2029*	2029	$ 75,334									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	101866	SM:Obsolete Elec-Replace 2030*	2030	$ 77,593									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	101867	SM:Obsolete Instr-Replace 2029*	2029	$ 75,334									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	101868	SM:Obsolete Instr-Replace 2030*	2030	$ 77,593									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	102022	SCHT:62001 Comp-Major O/H	2025	$ 419,814									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	102032	SCOR:61009 Top End-O/H incl. Cam Upgrade	2027	$ 528,052									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	102033	SCOR:61011 Top End-O/H incl. Cam Upgrade	2028	$ 523,552									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	102034	SCOR:61010 Top End-O/H incl. Cam Upgrade	2027	$ 528,052									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	501399	SCOR:541 MOP/OPP-Upgrade	2024	$ 713,675									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	501402	SCOR:TBD OPP-Upgrades	2024	$ 673,035									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	501524	SSOM:K-801 Isolation Valves - Replace	2023	$ 733,219									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	502781	SCOR:541 Drainage System-Upgrade	2023	$ 510,236									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	734136	SM:100MOV Yard Valve-Replace 2030*	2030	$ 554,310									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	734137	SM:100MOV Yard Valve-Replace 2031*	2031	$ 548,032									
STO - EGD	70 - Storage	Compression Stations	Fail	Dollar threshold	734138	SM:100MOV Yard Valve-Replace 2032*	2032	$ 532,121									

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Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
STO - EGD	**70 - Storage**	Compression Stations	**Fail**	Dollar threshold	**734319**	Methane Leak Remediation : Valve Replacement 2023*		$ 62,346									
STO - EGD	**70 - Storage**	Compression Stations	**Fail**	Dollar threshold	**734320**	Methane Leak Remediation : Valve Replacement 2024*		$ 64,069									
STO - EGD	**70 - Storage**	Compression Stations	**Fail**	Dollar threshold	**734321**	Methane Leak Remediation : Valve Replacement 2025*		$ 64,587									
STO - EGD	**70 - Storage**	Compression Stations	**Fail**	Dollar threshold	**734322**	Methane Leak Remediation : Valve Replacement 2026*		$ 65,384									
STO - EGD	**70 - Storage**	Compression Stations	**Fail**	Dollar threshold	**734323**	Methane Leak Remediation : Valve Replacement 2027*		$ 69,481									
STO - EGD	**70 - Storage**	Compression Stations	**Fail**	Dollar threshold	**734324**	Methane Leak Remediation : Valve Replacement 2028*		$ 68,888									
STO - EGD	**70 - Storage**	Compression Stations	**Fail**	Dollar threshold	**734325**	Methane Leak Remediation : Valve Replacement 2029*		$ 68,486									
STO - EGD	**70 - Storage**	Compression Stations	**Fail**	Dollar threshold	**734326**	Methane Leak Remediation : Valve Replacement 2030*		$ 70,539									
STO - EGD	**70 - Storage**	Compression Stations	**Fail**	Dollar threshold	**734327**	Methane Leak Remediation : Valve Replacement 2031*		$ 69,740									
STO - EGD	**70 - Storage**	Compression Stations	**Fail**	Dollar threshold	**734328**	Methane Leak Remediation : Valve Replacement 2032*		$ 67,716									
STO - EGD	**70 - Storage**	Compression Stations	**Fail**	Dollar threshold	**734330**	SCOR:525 UPS-Replace*	**2032**	$ 178,769									
STO - EGD	**70 - Storage**	Compression Stations	**Fail**	Dollar threshold	**734331**	SCOR:HMI PCs-Replace*	**2031**	$ 90,663									
STO - EGD	**70 - Storage**	Compression Stations	**Fail**	Dollar threshold	**734332**	SCOR:Obsolete Mech-Replace 2031*	**2031**	$ 132,507									
STO - EGD	**70 - Storage**	Compression Stations	**Fail**	Dollar threshold	**734333**	SCOR:Obsolete Mech-Replace 2032*	**2032**	$ 128,659									
STO - EGD	**70 - Storage**	Compression Stations	**Fail**	Dollar threshold	**734334**	SM:Obsolete Elec-Replace 2031*	**2031**	$ 76,715									
STO - EGD	**70 - Storage**	Compression Stations	**Fail**	Dollar threshold	**734335**	SM:Obsolete Elec-Replace 2032*	**2032**	$ 74,487									
STO - EGD	**70 - Storage**	Compression Stations	**Fail**	Dollar threshold	**734336**	SM:Obsolete Instr-Replace 2031*	**2031**	$ 76,715									
STO - EGD	**70 - Storage**	Compression Stations	**Fail**	Dollar threshold	**734337**	SM:Obsolete Instr-Replace 2032*	**2032**	$ 74,487									
STO - EGD	**70 - Storage**	Compression Stations	**Fail**	Dollar threshold	**734338**	SM:SCADA-Annual Upgrade 2029*	**2029**	$ 75,334									
STO - EGD	**70 - Storage**	Compression Stations	**Fail**	Dollar threshold	**734339**	SM:SCADA-Annual Upgrade 2030*	**2030**	$ 77,593									
STO - EGD	**70 - Storage**	Compression Stations	**Fail**	Dollar threshold	**734340**	SM:SCADA-Annual Upgrade 2031*	**2031**	$ 76,714									
STO - EGD	**70 - Storage**	Compression Stations	**Fail**	Dollar threshold	**734341**	SM:SCADA-Annual Upgrade 2032*	**2032**	$ 74,487									
STO - EGD	**70 - Storage**	Compression Stations	**Fail**	Dollar threshold	**734342**	SM:FIMP Recommend'ns-Implement 2031*	**2031**	$ 69,740									
STO - EGD	**70 - Storage**	Compression Stations	**Fail**	Dollar threshold	**734343**	SM:FIMP Recommend'ns-Implement 2029*	**2029**	$ 68,486									
STO - EGD	**70 - Storage**	Compression Stations	**Fail**	Dollar threshold	**734344**	SM:FIMP Recommend'ns-Implement 2030*	**2030**	$ 70,539									
STO - EGD	**70 - Storage**	Compression Stations	**Fail**	Dollar threshold	**734345**	SM:FIMP Recommend'ns-Implement 2032*	**2032**	$ 67,716									
STO - EGD	**70 - Storage**	Compression Stations	**Fail**	Dollar threshold	**736505**	SCOR: K711 MOD Hdr Valves-Replace	**2023**	$ 810,492									
STO - EGD	**70 - Storage**	Compression Stations	**Fail**	Timing	**12959**	SM:100MOD Hdr Valves-Replace*	**2023**	$ 2,880,365				Within 3 years, supply side not applicable					
STO - EGD	**70 - Storage**	Compression Stations	**Fail**	Timing	**12960**	SM:100MOD Hdr Valves-Replace*	**2025**	$ 1,989,272				Within 3 years, supply side not applicable					
STO - EGD	**70 - Storage**	Compression Stations	**Pass**		**5624**	SCOR:60004-Fdn Blk-Replace	**2023**	$ 3,366,661	**Issue/Concern: Due to the age of the compressor infrastructure, hours operating, 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 be diminished dramatically if repairs are not performed. 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. The 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: Compressor foundations** **Related Programs: Not applicable**	In Progress							
STO - EGD	**70 - Storage**	Compression Stations	**Pass**		**12884**	SCOR:60011-Fdn Blk-Replace	**2032**	$ 2,992,383	**Issue/Concern: Due to the age of the compressor infrastructure, hours operating 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. 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. The 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: Compressor foundations.** **Related Program: Not applicable.**	In Progress							

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Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
STO - EGD	**70 - Storage**	Compression Stations	**Pass**		**12961**	SM:100MOD Hdr Valves-Replace*	**2026**	$ 3,020,739	***Issue/Concern* Operations have identified compressor station yard isolation valves that to not provide sufficient seal quality that they could be trusted to provide isolation during normal maintenance activities or emergency situations. Valve condition - i.e. it's ability to perform it's intended function - 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 business case 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; and (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* ¼ Turn Isolation valves . There are dozens of these valves in service. *Related Program* Not Applicable**	Complete	**Fail**	See investment description, IRPAs not appliable					
STO - EGD	**70 - Storage**	Compression Stations	**Pass**		**100901**	Dawn to Corunna	**2023**	$ 165,101,440	**Issue/Concern/Opportunity:** **EGI recognizes its obligation to meet the firm demands of its customers; and as a result, assets are continually evaluated to identify hazards and to assess risks in order to ensure that they remain reliable, suitable, and fit for continued service. To this end, an Asset Health Review (AHR) was performed in 2018 and updated in 2021 as part of EGI's comprehensive Reliability, Availability and Maintainability (RAM) Study for the Corunna Compressor Station (CCS), which was completed by a consultant. The results of this study indicate that the health and maintainability of certain compressor units at the CCS are in decline. Reasons for this decline include, but are not limited to performance, functional issues with custom components (i.e., spare parts) and wear. As a result of these assessments, EGI has identified increasing obsolescence and reliability risks associated with certain CCS compressor units and is experiencing a need for increased maintenance and repair work to keep the units operational going forward.** **Further, as a result of the compressor units' obsolescence and reliability issues, EGI has experienced continued and increasing compressor unit downtime and long lead repair time. This has created a need for increased maintenance and repair work performed by EGI personnel at the CCS. EGI has also undertaken comprehensive studies, including a site-wide quantitative risk assessment (QRA) to determine the severity of the increasing safety risks, and has determined that the current configuration of compressor units (which includes multiple compressor units in close proximity within a single building) results in an excessive level of process safety risk.** **Assets: Compressors K701, K702, K703, K705, K706, K707 and K708** **Related Investments: 734634 - Dawn to Corunna (Dawn Tie-in)**	Complete	**Fail**	LTC in progress					
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Fail**	Dollar threshold	**1918**	NPS 24 Mid Kimball Transmission Pipeline Retrofit		$ 799,999									
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Fail**	Dollar threshold	**1919**	NPS 20 South Mid Kimball Gathering Pipeline Retrofit		$ 1,120,343									
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Fail**	Dollar threshold	**1920**	NPS 16 South Mid Kimball Gathering Pipeline Retrofit		$ 1,024,240									
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Fail**	Dollar threshold	**1921**	2024 Depth of Cover Mitigation Program*		$ 640,688									
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Fail**	Dollar threshold	**1923**	2025 Depth of Cover Mitigation Program*		$ 419,555									
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Fail**	Dollar threshold	**1924**	2025 Dig Program S&T*		$ 775,041									
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Fail**	Dollar threshold	**6376**	LCRW:Wells-Upgrade	**2025**	$ 516,694									
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Fail**	Dollar threshold	**8859**	PM:Wells-Acidize 2024*	**2024**	$ 317,781									
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Fail**	Dollar threshold	**8860**	PM:Wells-Acidize 2026*	**2026**	$ 324,304									
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Fail**	Dollar threshold	**8861**	PM:Wells-Acidize 2028*	**2028**	$ 341,687									
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Fail**	Dollar threshold	**8971**	LM:Well Loops-Adjust*	**2023**	$ 88,587									
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Fail**	Dollar threshold	**8972**	LM:Well Loops-Adjust*	**2024**	$ 91,036									
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Fail**	Dollar threshold	**8973**	LM:Well Loops-Adjust*	**2025**	$ 91,772									
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Fail**	Dollar threshold	**8974**	LM:Well Loops-Adjust*	**2026**	$ 92,905									
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Fail**	Dollar threshold	**8975**	LM:Well Loops-Adjust*	**2027**	$ 98,725									
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Fail**	Dollar threshold	**8976**	LM:Well Loops-Adjust*	**2028**	$ 97,884									
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Fail**	Dollar threshold	**8991**	LM:Leaking Valves-Replace*	**2023**	$ 382,802									
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Fail**	Dollar threshold	**8992**	LM:Leaking Valves-Replace*	**2024**	$ 197,332									
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Fail**	Dollar threshold	**8993**	LM:Leaking Valves-Replace*	**2025**	$ 198,927									
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Fail**	Dollar threshold	**8994**	LM:Leaking Valves-Replace*	**2026**	$ 201,383									
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Fail**	Dollar threshold	**8995**	LM:Leaking Valves-Replace*	**2027**	$ 214,000									
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Fail**	Dollar threshold	**8997**	LM:Leaking Valves-Replace*	**2028**	$ 212,177									

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STO - EGD	70 - Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	9184	LM:MS UPS-Replace*	2023	$ 17,145									
STO - EGD	70 - Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	9185	LM:MS UPS-Replace*	2024	$ 17,619									
STO - EGD	70 - Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	9186	LM:MS UPS-Replace*	2025	$ 17,761									
STO - EGD	70 - Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	9187	LM:MS UPS-Replace*	2026	$ 17,981									
STO - EGD	70 - Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	9188	LM:MS UPS-Replace*	2027	$ 19,107									
STO - EGD	70 - Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	9189	LM:MS UPS-Replace*	2028	$ 18,944									
STO - EGD	70 - Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	9545	PM:Well Casing-Replace Program 2023*	2023	$ 263,411									
STO - EGD	70 - Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	9546	PM:Well Casing-Replace Program 2024*	2024	$ 270,693									
STO - EGD	70 - Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	9547	PM:Well Casing-Replace Program 2025*	2025	$ 272,882									
STO - EGD	70 - Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	9548	PM:Well Casing-Replace Program 2026*	2026	$ 276,250									
STO - EGD	70 - Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	9549	PM:Well Casing-Replace Program 2027*	2027	$ 293,558									
STO - EGD	70 - Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	9550	PM:Well Casing-Replace Program 2028*	2028	$ 291,056									
STO - EGD	70 - Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	9583	PM:Roads&Laneways-Improve*	2023	$ 82,296									
STO - EGD	70 - Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	9584	PM:Roads&Laneways-Improve*	2024	$ 84,571									
STO - EGD	70 - Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	9585	PM:Roads&Laneways-Improve*	2025	$ 85,255									
STO - EGD	70 - Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	9586	PM:Roads&Laneways-Improve*	2026	$ 86,307									
STO - EGD	70 - Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	9587	PM:Roads&Laneways-Improve*	2027	$ 91,715									
STO - EGD	70 - Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	9588	PM:Roads&Laneways-Improve*	2028	$ 90,933									
STO - EGD	70 - Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	13046	LSEC:TS22H G/L-Modify	2024	$ 962,599									
STO - EGD	70 - Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	13048	LSEC:TS23H G/L-Modify	2024	$ 962,599									
STO - EGD	70 - Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	16808	MM:ESD Bottles-Upgrade*	2023	$ 149,629									
STO - EGD	70 - Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	16809	MM:Atm Liquids Tanks-Replace - 2023*	2023	$ 249,382									
STO - EGD	70 - Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	16810	MM:Atm Liquids Tanks-Replace - 2024*	2024	$ 256,275									
STO - EGD	70 - Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	16811	MM:Atm Liquids Tanks-Replace - 2025*	2025	$ 258,347									
STO - EGD	70 - Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	16812	MM:Atm Liquids Tanks-Replace - 2026*	2026	$ 261,536									
STO - EGD	70 - Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	16823	MM:Atm Liquids Tanks-Replace - 2027*	2027	$ 277,922									
STO - EGD	70 - Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	16833	PM:Well Tools-Purchase*	2023	$ 104,741									
STO - EGD	70 - Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	16834	PM:Well Tools-Purchase*	2025	$ 108,506									
STO - EGD	70 - Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	16835	LM:Lateral Separator-Build*	2023	$ 1,184,566									
STO - EGD	70 - Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	101184	PM:Roads&Laneways-Improve*	2029	$ 90,401									
STO - EGD	70 - Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	101185	PM:Roads&Laneways-Improve*	2030	$ 93,112									
STO - EGD	70 - Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	101902	PM:Well Tools-Purchase*	2027	$ 116,727									
STO - EGD	70 - Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	101903	PM:Well Tools-Purchase*	2029	$ 115,056									
STO - EGD	70 - Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	101904	LM:Leaking Valves-Replace*	2029	$ 210,936									
STO - EGD	70 - Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	101905	LM:Leaking Valves-Replace*	2030	$ 217,261									

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STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Fail**	Dollar threshold	**101907**	PM:Wells-Acidize 2023*	**2023**	$ 309,234									
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Fail**	Dollar threshold	**101908**	PM:Wells-Acidize 2025*	**2025**	$ 320,350									
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Fail**	Dollar threshold	**101909**	PM:Wells-Acidize 2027*	**2027**	$ 344,624									
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Fail**	Dollar threshold	**101910**	PM:Wells-Acidize 2029*	**2029**	$ 339,690									
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Fail**	Dollar threshold	**101911**	PM:Wells-Acidize 2030*	**2030**	$ 349,875									
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Fail**	Dollar threshold	**101912**	LM:Well Loops-Adjust*	**2029**	$ 97,312									
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Fail**	Dollar threshold	**101913**	LM:Well Loops-Adjust*	**2030**	$ 100,230									
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Fail**	Dollar threshold	**101914**	PM:Roads&Laneways-Improve*	**2031**	$ 92,057									
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Fail**	Dollar threshold	**101915**	PM:Roads&Laneways-Improve*	**2032**	$ 89,385									
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Fail**	Dollar threshold	**101916**	PM:Well Casing-Replace Program 2029*	**2029**	$ 289,355									
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Fail**	Dollar threshold	**101917**	PM:Well Casing-Replace Program 2030*	**2030**	$ 298,031									
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Fail**	Dollar threshold	**102418**	Rectifier Ground Bed Replacement Program*	**2021**	$ 1,342,470									
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Fail**	Dollar threshold	**102794**	2026 Depth of Cover Mitigation Program*		$ 539,418									
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Fail**	Dollar threshold	**102795**	2027 Depth of Cover Mitigation Program*		$ 573,215									
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Fail**	Dollar threshold	**102796**	2028 Depth of Cover Mitigation Program*		$ 568,330									
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Fail**	Dollar threshold	**102797**	2029 Depth of Cover Mitigation Program*		$ 565,008									
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Fail**	Dollar threshold	**102798**	2030 Depth of Cover Mitigation Program*		$ 581,949									
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Fail**	Dollar threshold	**735061**	PM:Well Casing-Replace Program 2031*	**2030**	$ 294,656									
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Fail**	Dollar threshold	**735062**	PM:Well Casing-Replace Program 2032*	**2030**	$ 286,101									
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Fail**	Dollar threshold	**735063**	PM:Wells-Acidize 2031*	**2031**	$ 345,912									
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Fail**	Dollar threshold	**735064**	PM:Wells-Acidize 2032*	**2032**	$ 335,869									
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Fail**	Dollar threshold	**735359**	PM:Well Tools-Purchase - 2031*	**2029**	$ 117,164									
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Fail**	Dollar threshold	**735376**	2031 Depth of Cover Mitigation Program*		$ 575,358									
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Fail**	Dollar threshold	**735377**	2032 Depth of Cover Mitigation Program*		$ 558,653									
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Fail**	Dollar threshold	**735399**	LM:MS UPS-Replace - 2029*	**2029**	$ 18,834									
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Fail**	Dollar threshold	**735400**	LM:MS UPS-Replace - 2030*	**2030**	$ 19,398									
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Fail**	Dollar threshold	**735401**	LM:MS UPS-Replace - 2031*	**2031**	$ 19,179									
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Fail**	Dollar threshold	**735402**	LM:MS UPS-Replace - 2032*	**2032**	$ 18,622									
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Fail**	Dollar threshold	**735992**	Bluewater A1 Well	**2023**	$ 1,119,732									
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Fail**	Dollar threshold	**736101**	New Well Lateral/Crossover (Well Lifecycle Replacement)*	**2020**	$ 1,312,725									
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Fail**	Timing	**1917**	2023 Dig Program S&T*	**2023**	$ 2,493,823				Within 3 years, supply side not applicable					
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Fail**	Timing	**1922**	2024 Dig Program S&T*	**2024**	$ 3,331,580				Within 3 years, supply side not applicable					
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Fail**	Timing	**736855**	2025 S&T Pipelines Integrity Program*	**2025**	$ 3,965,626				Within 3 years, supply side not applicable					

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Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Pass**		**6377**	PCRW:Wells-Upgrade	**2023**	$ 12,841,157	**Issue/Concern: Wells at Crowland are much older than other wells at 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 1970s 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 225 m) plus a surface casing that runs from the surface to a depth of about 20 m. 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 2 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 they have not been considered for integrity inspections until recently and the gathering system pipe condition is unknown after 50 to 100 years of operation. Assets: 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.**	Planned							
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Pass**		**13044**	PSEC:TS22H Well-Install	**2024**	$ 3,182,592	**Issue/Concern: Micro-annulus leaks have been occurring on wells that have been relined. Relining a well may be performed when the integrity of an existing casing is inadequate, and a smaller diameter casing is installed inside the original casing (concentrically). A recent rash of these relined wells has experienced leakage between the two casings. Concerns: 1.Localized leakage can be prevented by sealing the flow path at the wellhead (casing vent). This action causes pressure in the space between the two casings to achieve full reservoir pressure. 2.If the annulus space is allowed to be pressurized, there is the potential for a breach of the original casing; the original casings are known to have inadequate integrity. 3.A breach of the original casing could occur anywhere along the well string which is 2,000 ft long/deep. Leaking, unodourized gas could come to surface at unpredictable locations. About half of the relined wells operated by EGI are those which have not yet started to leak. Of the 20+ relined wells currently in-service at EGD Storage, 11 were recently found to be actively leaking and are being or have been abandoned. The mechanism by which a relined well becomes a leaking well has not been conclusively determined. The remaining (non-leaking) wells are expected to develop a leak in the short term. Once the wells are actively leaking, the problem becomes a compliance issue as follows: •CSA Z341.1-14 - 5.3.1 (a) The design of a well casing program shall provide control of pressures and fluids encountered by the well. •CSA Z341.1-14 - 5.3.6 (c) Well casings shall be set and cemented at sufficient depth to ensure isolation of storage zones. •OGSRA (O/Reg 245.97) - 17 (1) An operator of a well...shall provide casing and blowout prevention equipment and maintain it in such a condition that any oil, gas or water encountered can be effectively controlled. •OGSRA (O/Reg 245.97) - 17 (3) The operator shall ensure that the well does not flow uncontrolled. •O. Reg. 22/00, s. 6 (2) Well abandonments resulting from the Leaking and Relined well replacement programs will diminish the flow capacity of the associated reservoir. This performance degradation negatively impacts peak day deliverability. Reservoir performance deterioration, due to abandonment of relined wells, is currently unknown. Assets: Seckerton reservoir (Wells and Well Equipment asset program) and gathering system (Field Lines asset program).**	Planned							
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Pass**		**13047**	PSEC:TS23H Well-Install	**2024**	$ 3,182,592	**Issue/Concern: Well abandonments resulting from abandoned wells since 2007 have already diminished the flow capacity of Seckerton. The proposed relined well replacement program will diminish the flow capacity of the Seckerton Reservoir even further. In addition, wells on the northern saddle of Seckerton (referred to as Seckerton North) are being shut in during low-end withdrawal in order to mitigate crude oil carryover. The North and South saddles have limited interconnected permeability, meaning that gas migrates very slowly between the two saddles. Shutting in wells has the effect of stranding an estimated 1.5 BCF for three weeks at the end of the withdrawal cycle. This performance problem negatively impacts peak day deliverability. Assets: Seckerton reservoir (Wells and Well Equipment asset program) and gathering system (Field Lines asset program). Related Programs: Installation of wells is performed by the Reservoir group (Wells and Well Equipment asset program), installation of laterals is performed by the project execution group (Field Lines asset program). This separation is based on skill set and qualifications. There is a programmatic time dependence between the two asset programs.**	Planned							
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Pass**		**102767**	2026 Dig Program S&T*		$ 1,788,905	**2026 forecast: This is a program budget placeholder, estimated using an average of the spend profile between 2021-2025 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 inline 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 that are identified through the inspections.**	Complete	**Fail**	See investment description, IRPAs not appliable					
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Pass**		**102768**	2027 Dig Program S&T*		$ 2,167,793	**2027 forecast: This is a program budget placeholder, estimated using an average of the spend profile between 2021-2025 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 inline 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 that are identified through the inspections.**	Complete	**Fail**	See investment description, IRPAs not appliable					
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Pass**		**102769**	2028 Dig Program S&T*		$ 2,149,320	**2028 forecast: This is a program budget placeholder, estimated using an average of the spend profile between 2021-2025 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 inline 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 that are identified through the inspections.**	Complete	**Fail**	See investment description, IRPAs not appliable					

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Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Pass**		**102770**	2029 Dig Program S&T*		$ 2,136,757	**2029 forecast: This is a program budget placeholder, estimated using an average of the spend profile between 2021-2025 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 inline 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 that are identified through the inspections.**	Complete	**Fail**	See investment description, IRPAs not appliable					
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Pass**		**102771**	2030 Dig Program S&T*		$ 2,200,825	**2030 forecast: This is a program budget placeholder, estimated using an average of the spend profile between 2021-2025 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 inline 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 that are identified through the inspections.**	Complete	**Fail**	See investment description, IRPAs not appliable					
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Pass**		**102788**	2026 S&T Pipelines Integrity Program*		$ 4,014,575	**2026 forecast: This is a program budget placeholder, estimated using an average of the spend profile between 2021-2024 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 inline 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 that are identified through the inspections.**	Complete	**Fail**	See investment description, IRPAs not appliable					
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Pass**		**102789**	2027 S&T Pipelines Integrity Program*		$ 4,266,106	**2027 forecast: This is a program budget placeholder, estimated using an average of the spend profile between 2021-2024 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 inline 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 that are identified through the inspections.**	Complete	**Fail**	See investment description, IRPAs not appliable					
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Pass**		**102790**	2028 S&T Pipelines Integrity Program*		$ 4,229,751	**2028 forecast: This is a program budget placeholder, estimated using an average of the spend profile between 2021-2024 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 inline 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 that are identified through the inspections.**	Complete	**Fail**	See investment description, IRPAs not appliable					
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Pass**		**102792**	2029 S&T Pipelines Integrity Program*		$ 4,205,028	**2029 forecast: This is a program budget placeholder, estimated using an average of the spend profile between 2021-2024 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 inline 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 that are identified through the inspections.**	Complete	**Fail**	See investment description, IRPAs not appliable					
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Pass**		**102793**	2030 S&T Pipelines Integrity Program*		$ 4,331,110	**2030 forecast: This is a program budget placeholder, estimated using an average of the spend profile between 2021-2024 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 inline 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 that are identified through the inspections.**	Complete	**Fail**	See investment description, IRPAs not appliable					
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Pass**		**733835**	NPS 20 Seckerton Gathering Retrofit		$ 1,870,367	**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. Assets: NPS 20 Seckerton Gathering System Related Programs: Transmission Integrity Management Program (TIMP)**	Complete	**Fail**	See investment description, IRPAs not appliable					
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Pass**		**735379**	2031 Dig Program S&T*		$ 2,175,900	**2031 forecast: This is a program budget placeholder, estimated using an average of the spend profile between 2021-2025 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 inline 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 that are identified through the inspections.**	Complete	**Fail**	See investment description, IRPAs not appliable					
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Pass**		**735380**	2032 Dig Program S&T*		$ 2,112,726	**2032 forecast: This is a program budget placeholder, estimated using an average of the spend profile between 2021-2025 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 inline 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 that are identified through the inspections.**	Complete	**Fail**	See investment description, IRPAs not appliable					
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Pass**		**735381**	2031 S&T Pipelines Integrity Program*		$ 4,282,059	**2031 forecast: This is a program budget placeholder, estimated using an average of the spend profile between 2021-2024 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 inline 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 that are identified through the inspections.**	Complete	**Fail**	See investment description, IRPAs not appliable					

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STO - EGD	70 - Storage	Transmission Pipe & Underground Storage	Pass		735382	2032 S&T Pipelines Integrity Program*		$ 4,157,736	2032 forecast: This is a program budget placeholder, estimated using an average of the spend profile between 2021-2024 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 inline 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 that are identified through the inspections.	Complete	Fail	See investment description, IRPAs not appliable					
STO - EGD	70 - Storage	Transmission Pipe & Underground Storage	Pass		735385	MOP Verification Replacement Program 2025 - S&T Assets*	2030	$ 1,291,735	General: MOP verification is the process of reviewing all existing records for a pipeline system and confirming the maximum operating pressure of existing greater than 30 per cent SMYS pipeline systems based upon these records. While this is not currently mandated by code in Canada, it is required in the U.S. and is expected to become a requirement in Canada in the future. Given the number of pipelines greater than 30 per cent SMYS, MOP Verification will be a multi-year project requiring a dedicated team to complete the verifications and determine if any pipeline remediation is required. This forecast includes the costs of replacing sections of pipelines as identified through the MOP verification work. MOP verification was also included in the 2017 customer engagement survey: while 43 per cent of those surveyed recommend waiting for regulation requirements to keep costs down, 40 per cent recommend proactively implementing industry standard. Spreading the verifications over several years will keep costs down and proactively implement an industry standard, which provides additional support for this program. Starting this program as forecast will mitigate the need for higher expenditures in a shorter time frame to meet these expected future mandated requirements.	Complete	Fail	See investment description, IRPAs not appliable					
STO - EGD	70 - Storage	Transmission Pipe & Underground Storage	Pass		735386	MOP Verification Replacement Program 2026 - S&T Assets*	2031	$ 2,615,358	General: MOP verification is the process of reviewing all existing records for a pipeline system and confirming the maximum operating pressure of existing greater than 30 per cent SMYS pipeline systems based upon these records. While this is not currently mandated by code in Canada, it is required in the U.S. and is expected to become a requirement in Canada in the future. Given the number of pipelines greater than 30 per cent SMYS, MOP Verification will be a multi-year project requiring a dedicated team to complete the verifications and determine if any pipeline remediation is required. This forecast includes the costs of replacing sections of pipelines as identified through the MOP verification work. MOP verification was also included in the 2017 customer engagement survey: while 43 per cent of those surveyed recommend waiting for regulation requirements to keep costs down, 40 per cent recommend proactively implementing industry standard. Spreading the verifications over several years will keep costs down and proactively implement an industry standard, which provides additional support for this program. Starting this program as forecast will mitigate the need for higher expenditures in a shorter time frame to meet these expected future mandated requirements.	Complete	Fail	See investment description, IRPAs not appliable					
STO - EGD	70 - Storage	Transmission Pipe & Underground Storage	Pass		735387	MOP Verification Replacement Program 2027 - S&T Assets*	2032	$ 2,779,222	General: MOP verification is the process of reviewing all existing records for a pipeline system and confirming the maximum operating pressure of existing greater than 30 per cent SMYS pipeline systems based upon these records. While this is not currently mandated by code in Canada, it is required in the U.S. and is expected to become a requirement in Canada in the future. Given the number of pipelines greater than 30 per cent SMYS, MOP Verification will be a multi-year project requiring a dedicated team to complete the verifications and determine if any pipeline remediation is required. This forecast includes the costs of replacing sections of pipelines as identified through the MOP verification work. MOP verification was also included in the 2017 customer engagement survey: while 43 per cent of those surveyed recommend waiting for regulation requirements to keep costs down, 40 per cent recommend proactively implementing industry standard. Spreading the verifications over several years will keep costs down and proactively implement an industry standard, which provides additional support for this program. Starting this program as forecast will mitigate the need for higher expenditures in a shorter time frame to meet these expected future mandated requirements.	Complete	Fail	See investment description, IRPAs not appliable					
STO - EGD	70 - Storage	Transmission Pipe & Underground Storage	Pass		735388	MOP Verification Replacement Program 2028 - S&T Assets*	2033	$ 2,755,538	General: MOP verification is the process of reviewing all existing records for a pipeline system and confirming the maximum operating pressure of existing greater than 30 per cent SMYS pipeline systems based upon these records. While this is not currently mandated by code in Canada, it is required in the U.S. and is expected to become a requirement in Canada in the future. Given the number of pipelines greater than 30 per cent SMYS, MOP Verification will be a multi-year project requiring a dedicated team to complete the verifications and determine if any pipeline remediation is required. This forecast includes the costs of replacing sections of pipelines as identified through the MOP verification work. MOP verification was also included in the 2017 customer engagement survey: while 43 per cent of those surveyed recommend waiting for regulation requirements to keep costs down, 40 per cent recommend proactively implementing industry standard. Spreading the verifications over several years will keep costs down and proactively implement an industry standard, which provides additional support for this program. Starting this program as forecast will mitigate the need for higher expenditures in a shorter time frame to meet these expected future mandated requirements.	Complete	Fail	See investment description, IRPAs not appliable					
STO - EGD	70 - Storage	Transmission Pipe & Underground Storage	Pass		735389	MOP Verification Replacement Program 2029 - S&T Assets*	2034	$ 2,739,432	General: MOP verification is the process of reviewing all existing records for a pipeline system and confirming the maximum operating pressure of existing greater than 30 per cent SMYS pipeline systems based upon these records. While this is not currently mandated by code in Canada, it is required in the U.S. and is expected to become a requirement in Canada in the future. Given the number of pipelines greater than 30 per cent SMYS, MOP Verification will be a multi-year project requiring a dedicated team to complete the verifications and determine if any pipeline remediation is required. This forecast includes the costs of replacing sections of pipelines as identified through the MOP verification work. MOP verification was also included in the 2017 customer engagement survey: while 43 per cent of those surveyed recommend waiting for regulation requirements to keep costs down, 40 per cent recommend proactively implementing industry standard. Spreading the verifications over several years will keep costs down and proactively implement an industry standard, which provides additional support for this program. Starting this program as forecast will mitigate the need for higher expenditures in a shorter time frame to meet these expected future mandated requirements.	Complete	Fail	See investment description, IRPAs not appliable					
STO - EGD	70 - Storage	Transmission Pipe & Underground Storage	Pass		735390	MOP Verification Replacement Program 2030 - S&T Assets*	2035	$ 2,821,570	General: MOP verification is the process of reviewing all existing records for a pipeline system and confirming the maximum operating pressure of existing greater than 30 per cent SMYS pipeline systems based upon these records. While this is not currently mandated by code in Canada, it is required in the U.S. and is expected to become a requirement in Canada in the future. Given the number of pipelines greater than 30 per cent SMYS, MOP Verification will be a multi-year project requiring a dedicated team to complete the verifications and determine if any pipeline remediation is required. This forecast includes the costs of replacing sections of pipelines as identified through the MOP verification work. MOP verification was also included in the 2017 customer engagement survey: while 43 per cent of those surveyed recommend waiting for regulation requirements to keep costs down, 40 per cent recommend proactively implementing industry standard. Spreading the verifications over several years will keep costs down and proactively implement an industry standard, which provides additional support for this program. Starting this program as forecast will mitigate the need for higher expenditures in a shorter time frame to meet these expected future mandated requirements.	Complete	Fail	See investment description, IRPAs not appliable					
STO - EGD	70 - Storage	Transmission Pipe & Underground Storage	Pass		735391	MOP Verification Replacement Program 2031 - S&T Assets*	2036	$ 2,789,615	General: MOP verification is the process of reviewing all existing records for a pipeline system and confirming the maximum operating pressure of existing greater than 30 per cent SMYS pipeline systems based upon these records. While this is not currently mandated by code in Canada, it is required in the U.S. and is expected to become a requirement in Canada in the future. Given the number of pipelines greater than 30 per cent SMYS, MOP Verification will be a multi-year project requiring a dedicated team to complete the verifications and determine if any pipeline remediation is required. This forecast includes the costs of replacing sections of pipelines as identified through the MOP verification work. MOP verification was also included in the 2017 customer engagement survey: while 43 per cent of those surveyed recommend waiting for regulation requirements to keep costs down, 40 per cent recommend proactively implementing industry standard. Spreading the verifications over several years will keep costs down and proactively implement an industry standard, which provides additional support for this program. Starting this program as forecast will mitigate the need for higher expenditures in a shorter time frame to meet these expected future mandated requirements.	Complete	Fail	See investment description, IRPAs not appliable					
STO - EGD	70 - Storage	Transmission Pipe & Underground Storage	Pass		735392	MOP Verification Replacement Program 2032 - S&T Assets*	2037	$ 2,708,623	General: MOP verification is the process of reviewing all existing records for a pipeline system and confirming the maximum operating pressure of existing greater than 30 per cent SMYS pipeline systems based upon these records. While this is not currently mandated by code in Canada, it is required in the U.S. and is expected to become a requirement in Canada in the future. Given the number of pipelines greater than 30 per cent SMYS, MOP Verification will be a multi-year project requiring a dedicated team to complete the verifications and determine if any pipeline remediation is required. This forecast includes the costs of replacing sections of pipelines as identified through the MOP verification work. MOP verification was also included in the 2017 customer engagement survey: while 43 per cent of those surveyed recommend waiting for regulation requirements to keep costs down, 40 per cent recommend proactively implementing industry standard. Spreading the verifications over several years will keep costs down and proactively implement an industry standard, which provides additional support for this program. Starting this program as forecast will mitigate the need for higher expenditures in a shorter time frame to meet these expected future mandated requirements.	Complete	Fail	See investment description, IRPAs not appliable					

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Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Pass**		**735770**	A1 observation program*		$ 7,253,620	**Issue/Concern: Observation wells are required pursuant to Section 7.5 of CSA Z341 – Storage of hydrocarbons in underground formations . The observation well will monitor gas content and pressure in the underground storage area which will assist with the continued safe and reliable delivery of natural gas to our existing and future customers. Section 7.5: "Observation wells shall be incorporated into the storage facility and shall monitor pressures and the presence of hydrocarbons within the storage zone and associated permeable zones. The location and design of the observation well shall take into consideration: (a) locations within the storage zone that are suitable for monitoring reservoir pressures; (b) potential migratory paths from the reservoir to another formation; (c) fluid interface monitoring at the location of the spill point; (d) permeable zones and stratigraphic traps above the storage zone; and (e) low-permeability zones or formations adjacent to and in communication with" In addition, interpretations of the latest reservoir simulations indicate that the A-1 sucrosic dolomite may extend beyond the geographical edge of some DSAs. The DSA boundary protects the reef from any unwanted drilling by a third party. If the A-1 does, in fact, extend beyond the DSA boundary, a third party could receive permission to drill and if they penetrated the A-1 sucrosic they would be connected to the associated reef. EGD would then be forced to extend the DSA boundary and include, or buy out, the 3rd party. While the seismic provides a good interpretation of the A-1 it is not definitive and the only way to fully determine if the A-1 sucrosic is located beyond the boundary of the DSA is to drill a well. Mitigation of this risk will protect EGD's rights to the associated reservoir facility. Finally, the A1 Observation wells were originally proposed as a means to verify the integrity of the reservoir boundaries and demonstrate the relationship of low permeability zones to LUF. EGD receives rate recovery on LUF, and A1 zones were considered a potential means by which gas was leaking out of the reservoirs or becoming trapped, thereby creating LUF. The issue is that EGI must continue to investigate causes of LUF in order to argue for cost recovery from rates. This program drills one A1 well per year for 9 years. There are currently no A1 observation wells at the following pools. Airport Oil Springs East Mandaumin Oil City Bluewater Heritage**	Complete	**Fail**	See investment description, IRPAs not appliable					
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Pass**		**735974**	Well Lifecycle Replacement*	**2028**	$ 13,855,732	**Issue/Concern: This project is intended to recover lost design day deliverability due to well relines and abandonments. The deliverability of the new well is not intended to increase but maintain the deliverability. This project will drill one new vertical injection/withdrawal well and connect it to the existing gathering system of the desired pool. The new injection/withdrawal well will maintain the current split between the regulated/unregulated percentages of the pool. Asset: Wells Related Program: N/A**	Planned							
STO - EGD	**70 - Storage**	Transmission Pipe & Underground Storage	**Pass**		**735995**	Black Creek A1 Observation well	**2026**	$ 2,701,793	**Issue/Concern/Opportunity: The storage pool pressure at the Black Creek pool is monitored by a Guelph formation observation well. This well's pressure is monitored and recorded continuously. and represents an inventory by the pools specific Pressure/inventory ratio. These pressures/inventories are compared to daily metered gas injections and withdrawals from the pool to perform an annual inventory verification. All discrepancies arising from this verification must be investigated. Assets: This project drills one A1 observation well in the Black Creek pool DSA. The well will be a 5 1/2" production casing, cemented at least 20m into the A1 formation and perforated in the A1 formation. Pressures from this well will be conveyed to the SCADA system for continuous monitoring and recording. These pressures will be assessed on an ongoing basis and during inventory verifications to confirm structural integrity of the Black Creek storage pool. Any increase in pressure would be proof of gas migration to the A1 formation. Related Program: Well Casing Inspection, Maintenance and Replacements**	Planned							
STO - UG	**Div_53 - Union South Storage**	Distribution Stations	**Pass**		**48993**	SANDWICH YARD DRAINAGE	**2023**	$ 1,494,636	**Issue/Concern: Heater, Pressure Drop,Glycol,Pipe Integrity Assets: Sandwich Station Related Programs: Not applicable**	Planned							
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**48211**	Waubuno Pool PLC Upgrade	**2023**	$ 54,928									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**48217**	Tecumseh 2 PLC Upgrade	**2023**	$ 68,006									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**48219**	TCPL Dawn PLC Upgrade	**2023**	$ 480,526									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**48221**	Sombra/St. Clair Station PLC Upgrade	**2023**	$ 57,917									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**48223**	Siemens Valve Controllers Replacement - Dawn I & Parkway D*		$ 604,082									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**48224**	Sandwich Compressor Overhaul		$ 902,033									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**48229**	Parkway A PLC Upgrade	**2023**	$ 903,009									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**48237**	Lobo MCR PLC Upgrade	**2024**	$ 70,489									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**48270**	Enniskillen Pool Siemens MCC replacement	**2024**	$ 74,718									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**48271**	Enniskillen Pool PLC Upgrade	**2023**	$ 46,209									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**48273**	Dow A Pool Siemens MCC replacement	**2023**	$ 94,536									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**48274**	Dawn G Siemens MCC replacement	**2023**	$ 398,009									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**48275**	Dawn E Siemens MCC replacement	**2023**	$ 539,909									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**48278**	Dawn Aux 4 Siemens MCC replacement	**2024**	$ 118,422									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**48281**	Bright MCR PLC Upgrade	**2024**	$ 70,489									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**48283**	Bluewater, Mandaumin, Airport Station PLC Upgrade	**2023**	$ 105,372									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**48284**	Bickford Pool Siemens MCC replacement	**2026**	$ 81,712									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**48639**	Parkway Main Control Building - Fire Ga	**2023**	$ 174,374									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**48706**	Enniskillen Control Building	**2025**	$ 106,818									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**48712**	Large Diameter - Valve Replacement 2024	**2024**	$ 577,493									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**48723**	Obsolete MCC Replace 2030*	**2030**	$ 326,807									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**48726**	STO Paving replacements	**2026**	$ 569,467									

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Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	49904	Payne Compressor Stn Transformer	2024	$ 106,005									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	49908	DAWN YARD PAVING and TRENWAY REPLACE	2028	$ 137,617									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	49909	156 Control Room Building Replace	2023	$ 56,369									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	49953	167 Control Building	2026	$ 128,130									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	49959	Bright B Power Turbine - Mid life Overhaul	2025	$ 470,269									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	100113	Bright MCR MCC Replacement	2023	$ 161,919									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	100117	Obsolete PLC Program Upgrade 2025*	2025	$ 340,943									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	100167	Dawn G - Fire & Gas Detection Panel	2023	$ 91,111									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	100937	Storage: Recip Compressor O/H*	2031	$ 531,726									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	100939	OSE #2 Top End O/H	2023	$ 150,211									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	100940	Edys Mills Top End O/H	2026	$ 166,552									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101242	Lobo/Bright Compressor Station Lighting 2023	2023	$ 49,821									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101243	Lobo/Bright Compressor Station Lighting 2024	2024	$ 51,265									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101244	Lobo/Bright Compressor Station Lighting 2025	2025	$ 51,658									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101245	Lobo/Bright Compressor Station Lighting 2026	2026	$ 52,129									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101246	Lobo/Bright Compressor Station Lighting 2027	2027	$ 55,510									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101247	Lobo/Bright Compressor Station Lighting 2028	2028	$ 55,047									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101248	Lobo/Bright Compressor Station Lighting 2029	2029	$ 54,653									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101249	Lobo/Bright Compressor Station Lighting 2030*	2030	$ 56,590									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101257	Bright A Plant air compressors	2024	$ 275,548									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101259	Bright Ring Road Paving		$ 324,249									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101306	Parkway West Perimeter Security Path		$ 311,383									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101308	Parkway West Storage Quonset Hut		$ 180,602									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101310	Parkway/Hagar Compressor Building Lighting 2023	2023	$ 49,821									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101312	Parkway/Hagar Compressor Building Lighting 2024	2024	$ 51,265									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101313	Parkway/Hagar Compressor Building Lighting 2025	2025	$ 51,658									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101314	Parkway/Hagar Compressor Building Lighting 2026	2026	$ 52,129									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101315	Parkway/Hagar Compressor Building Lighting 2027	2027	$ 55,510									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101316	Parkway/Hagar Compressor Building Lighting 2028	2028	$ 55,047									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101317	Parkway/Hagar Compressor Building Lighting 2029	2029	$ 54,653									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101318	Parkway/Hagar Compressor Building Lighting 2030	2030	$ 56,590									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101571	Obsolete PLC Program Upgrade 2026*	2026	$ 417,031									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101572	Obsolete PLC Program Upgrade 2027*	2027	$ 444,078									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101573	Obsolete PLC Program Upgrade 2028*	2028	$ 440,376									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101574	Obsolete PLC Program Upgrade 2029*	2029	$ 437,223									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101575	Obsolete PLC Program Upgrade 2030*	2030	$ 452,720									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101576	Siemens Valve Controllers Replacement - Lobo D & Dawn H*		$ 1,247,938									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101845	Dawn Safety & Security Upgrades 2023*		$ 131,362									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101846	Dawn Safety & Security Upgrades 2024*		$ 135,168									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101847	Dawn Safety & Security Upgrades 2025*		$ 136,205									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101848	Dawn Safety & Security Upgrades 2026*		$ 137,447									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101849	Dawn Safety & Security Upgrades 2027*		$ 146,361									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101850	Dawn Safety & Security Upgrades 2028*		$ 145,141									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101851	Dawn Safety & Security Upgrades 2029*		$ 144,102									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101852	Dawn Safety & Security Upgrades 2030*		$ 149,209									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101855	TCO Safety & Security Upgrades 2023*		$ 78,184									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101856	TCO Safety & Security Upgrades 2024*		$ 80,450									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101857	TCO Safety & Security Upgrades 2025*		$ 81,067									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101858	TCO Safety & Security Upgrades 2026*		$ 81,806									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101859	TCO Safety & Security Upgrades 2027*		$ 87,111									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101860	TCO Safety & Security Upgrades 2028*		$ 86,385									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101861	TCO Safety & Security Upgrades 2029*		$ 85,767									

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STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101862	TCO Safety & Security Upgrades 2030*		$ 88,807									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101871	Obsolete Electrical-Replace 2023*	2023	$ 102,756									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101872	Obsolete Electrical-Replace 2024*	2024	$ 105,734									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101873	Obsolete Electrical-Replace 2025*	2025	$ 106,545									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101874	Obsolete Electrical-Replace 2026*	2026	$ 162,903									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101875	Obsolete Electrical-Replace 2027*	2027	$ 173,468									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101876	Obsolete Electrical-Replace 2028*	2028	$ 172,022									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101877	Obsolete Electrical-Replace 2029*	2029	$ 170,790									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101878	Obsolete Electrical-Replace 2030*	2030	$ 176,844									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101880	Obsolete Instrumentation-Replace 2023*	2023	$ 102,756									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101881	Obsolete Instrumentation-Replace 2024*	2024	$ 105,734									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101882	Obsolete Instrumentation-Replace 2025*	2025	$ 106,545									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101883	Obsolete Instrumentation-Replace 2026*	2026	$ 162,903									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101884	Obsolete Instrumentation-Replace 2031*	2031	$ 174,910									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101885	Obsolete Instrumentation-Replace 2027*	2027	$ 173,468									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101886	Obsolete Instrumentation-Replace 2028*	2028	$ 172,022									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101887	Obsolete Instrumentation-Replace 2029*	2029	$ 170,790									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101888	Obsolete Instrumentation-Replace 2030*	2030	$ 176,844									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101890	Dawn Compressor Building Lighting 2023	2023	$ 156,937									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101892	Dawn Compressor Building Lighting 2024	2024	$ 161,484									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101893	Dawn Compressor Building Lighting 2025	2025	$ 162,723									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101894	Dawn Compressor Building Lighting 2026	2026	$ 164,206									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101895	Dawn Compressor Building Lighting 2027	2027	$ 174,856									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101896	Dawn Compressor Building Lighting 2028	2028	$ 173,398									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101897	Dawn Compressor Building Lighting 2029	2029	$ 172,156									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101898	Dawn Compressor Building Lighting 2030	2030	$ 178,258									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101922	High Performance Coating Program 2023*	2022	$ 697,497									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101924	High Performance Coating Program 2024*	2023	$ 717,706									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101925	High Performance Coating Program 2025*	2025	$ 723,212									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101927	High Performance Coating Program 2026*	2026	$ 729,805									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101928	High Performance Coating Program 2027*	2027	$ 777,136									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101930	High Performance Coating Program 2028*	2028	$ 770,658									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101931	High Performance Coating Program 2029*	2029	$ 765,140									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101933	High Performance Coating Program 2030*	2030	$ 792,260									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101955	OSE #1 Top End O/H	2028	$ 165,967									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101960	Dawn Aux 4-2 Gen Top End O/H	2025	$ 195,267									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101961	Dawn Aux 3 Gen Top End O/H	2023	$ 188,324									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101962	OSE #1 Bottom End O/H	2028	$ 138,306									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101963	OSE #2 Bottom End O/H	2023	$ 125,176									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	101980	OSE #1 Compressor Crankcase Rebuild		$ 68,809									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	102344	Dawn Aux 4-1 Gen Turbo Rebuild	2025	$ 21,696									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	102348	Edys Mills Engine Turbo Rebuild	2025	$ 18,339									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	102355	OSE #2 Compressor Crankcase Rebuild		$ 62,277									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	102356	Edys Mills Compressor Crankcase Rebuild		$ 65,161									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	102731	STO - UPS Battery replacements 2023	2023	$ 149,464									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	102732	STO - UPS Battery replacements 2024	2024	$ 153,794									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	102733	STO - UPS Battery replacements 2025	2025	$ 154,974									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	103156	FIMP Recommend'ns-Implement*	2022	$ 934,148									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	103157	FIMP Recommend'ns-Implement*	2024	$ 128,162									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	103159	FIMP Recommend'ns-Implement*	2025	$ 129,145									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	501141	Lobo C GGLO Scheduling Valve & Controller replacement	2023	$ 324,461									
STO - UG	Div_53 - Union South Storage	Compression Stations	Fail	Dollar threshold	501148	Dawn H GGLO Sheculing valve and controller replacement	2023	$ 353,838									

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Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**501149**	Bright A1 GGLO valve & Controller replacement	**2023**	$ 276,508									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**501150**	Bright C GGLO scheduling valve and Controller replacement	**2022**	$ 89,678									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**501151**	Bright A2 GGLO scheduling valve & controller replacement	**2025**	$ 286,702									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**501152**	Parkway C GGLO scheduling valve & controller replacement	**2023**	$ 66,013									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**501153**	Parkway B GGLO scheduling valve & controller replacement	**2025**	$ 362,124									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**503219**	Lobo B Power Gas Dryer Upgrade	**2023**	$ 137,008									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**503237**	Lobo North Yard Drip Tank Replacement	**2023**	$ 51,067									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**733364**	Dawn Salt Building - Replace		$ 373,659									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**733980**	Parkway Leaking Valves - Replace - P611 (plug 3") & P603 (plug 8")	**2023**	$ 622,765									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**734139**	Methane Leak Remediation : Valve Replacement 2023*		$ 249,106									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**734140**	Methane Leak Remediation : Valve Replacement 2024*		$ 256,324									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**734141**	Methane Leak Remediation : Valve Replacement 2025*		$ 258,290									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**734142**	Methane Leak Remediation : Valve Replacement 2026*		$ 260,645									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**734143**	Methane Leak Remediation : Valve Replacement 2027*		$ 277,549									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**734144**	Methane Leak Remediation : Valve Replacement 2028*		$ 275,235									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**734145**	Methane Leak Remediation : Valve Replacement 2029*		$ 273,264									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**734146**	Methane Leak Remediation : Valve Replacement 2030*		$ 282,950									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**734147**	Methane Leak Remediation : Valve Replacement 2031*		$ 279,856									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**734148**	Methane Leak Remediation : Valve Replacement 2032*		$ 271,598									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**734150**	Large Diameter - Valve Replacement 2025*	**2025**	$ 968,588									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**734151**	Large Diameter - Valve Replacement 2027*	**2027**	$ 1,040,807									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**734152**	Large Diameter - Valve Replacement 2029*	**2029**	$ 1,024,741									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**734153**	Large Diameter - Valve Replacement 2030*	**2030**	$ 1,061,062									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**734154**	Large Diameter - Valve Replacement 2031*	**2031**	$ 1,049,459									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**734155**	Large Diameter - Valve Replacement 2032*	**2032**	$ 1,018,493									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**734156**	Dawn Safety & Security Upgrades 2031*		$ 147,578									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**734158**	Dawn Safety & Security Upgrades 2032*		$ 143,223									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**734161**	TCO Safety & Security Upgrades 2031*		$ 87,836									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**734162**	TCO Safety & Security Upgrades 2032*		$ 85,244									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**734196**	Obsolete Electrical-Replace 2031*	**2031**	$ 174,910									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**734197**	Obsolete Electrical-Replace 2032*	**2032**	$ 169,749									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**734198**	Obsolete Instrumentation-Replace 2032*	**2032**	$ 169,749									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**734199**	Obsolete PLC Program Upgrade 2031*	**2031**	$ 447,769									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**734200**	Obsolete PLC Program Upgrade 2032*	**2032**	$ 434,557									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**734203**	Obsolete MCC Replace 2031*	**2038**	$ 323,233									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**734204**	Obsolete MCC Replace 2032*	**2039**	$ 313,696									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**734205**	STO Obsolete Mechanical - Replace 2023*	**2023**	$ 164,410									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**734206**	STO Obsolete Mechanical - Replace 2024*	**2024**	$ 169,174									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**734207**	STO Obsolete Mechanical - Replace 2025*	**2025**	$ 170,471									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**734208**	STO Obsolete Mechanical - Replace 2026*	**2026**	$ 172,025									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**734209**	STO Obsolete Mechanical - Replace 2027*	**2027**	$ 183,182									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**734210**	STO Obsolete Mechanical - Replace 2028*	**2028**	$ 181,655									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**734211**	STO Obsolete Mechanical - Replace 2029*	**2029**	$ 180,354									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**734212**	STO Obsolete Mechanical - Replace 2030*	**2030**	$ 186,747									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**734213**	STO Obsolete Mechanical - Replace 2031*	**2031**	$ 184,705									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**734214**	STO Obsolete Mechanical - Replace 2032*	**2032**	$ 179,255									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**734215**	TCO Obsolete Mechanical - Replace 2023*	**2023**	$ 217,968									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**734216**	TCO Obsolete Mechanical - Replace 2024*	**2024**	$ 224,283									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**734217**	TCO Obsolete Mechanical - Replace 2025*	**2025**	$ 226,004									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**734219**	TCO Obsolete Mechanical - Replace 2026*	**2026**	$ 228,064									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**734220**	TCO Obsolete Mechanical - Replace 2027*	**2027**	$ 242,855									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**734221**	TCO Obsolete Mechanical - Replace 2028*	**2028**	$ 240,831									

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Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**734222**	TCO Obsolete Mechanical - Replace 2029*	**2029**	$ 239,106									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**734223**	TCO Obsolete Mechanical - Replace 2030*	**2030**	$ 247,581									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**734224**	TCO Obsolete Mechanical - Replace 2031*	**2031**	$ 244,874									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**734225**	TCO Obsolete Mechanical - Replace 2032*	**2032**	$ 237,648									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**734236**	Parkway Ultrasonic Meter Upgrades 2023*		$ 106,294									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**734237**	Parkway Ultrasonic Meter Upgrades 2024*		$ 109,374									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**734274**	High Performance Coating Program 2031*	**2030**	$ 783,596									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**734275**	High Performance Coating Program 2032*	**2032**	$ 760,475									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**734347**	STO - UPS Battery replacements 2026	**2026**	$ 156,387									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**734348**	STO - UPS Battery replacements 2027	**2027**	$ 166,529									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**734349**	STO - UPS Battery replacements 2028	**2028**	$ 165,141									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**734350**	STO - UPS Battery replacements 2029	**2029**	$ 163,959									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**734351**	STO - UPS Battery replacements 2030	**2030**	$ 169,770									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**734352**	STO - UPS Battery replacements 2031	**2031**	$ 167,913									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**734353**	STO - UPS Battery replacements 2032	**2032**	$ 162,959									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**735627**	Bright A1 Scrubber Replacement	**2024**	$ 1,268,802									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**735656**	Parkway East Generator Control Upgrade	**2023**	$ 1,245,530									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**735978**	STO Moisture Analyzer Upgrade 2023*		$ 74,732									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**736014**	STO Moisture Analyzer Upgrade 2024*		$ 76,897									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**736015**	STO Moisture Analyzer Upgrade 2025*		$ 77,487									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**736016**	STO Moisture Analyzer Upgrade 2026*		$ 78,193									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**736017**	STO Moisture Analyzer Upgrade 2027*		$ 83,265									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**736018**	STO Moisture Analyzer Upgrade 2028*		$ 82,570									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**736019**	STO Moisture Analyzer Upgrade 2029*		$ 81,979									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**736021**	STO Moisture Analyzer Upgrade 2030*		$ 84,885									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**736022**	STO Moisture Analyzer Upgrade 2031*		$ 83,957									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**736023**	STO Moisture Analyzer Upgrade 2032*		$ 81,479									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**736182**	Lobo C Siemens Valve Controllers Replacement	**2023**	$ 105,870									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**736274**	Dawn Fire Pump 1	**2023**	$ 940,375									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**736276**	Large Diameter - Valve Replacement 2026*	**2026**	$ 977,417									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**736277**	Large Diameter - Valve Replacement 2028*	**2028**	$ 1,032,131									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**736325**	Parkway C Siemens Valve Controllers Replacement	**2023**	$ 105,870									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Fail**	Dollar threshold	**736922**	Dawn Fire Pond Weir	**2023**	$ 62,277									
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Pass**		**48231**	Parkway A Gas Generator(38148) End-of-Life Overhaul	**2027**	$ 2,886,505	**Issue/Concern/Opportunity: The consequence of compressor failure is dominated by gas cost impacts to customers. The compressor package is comprised of a gas turbine engine driver, compressor, power turbine and ancillary equipment such as lube oil, fuel supply, and electronic control systems, which are required for the compressor to operate. The gas turbine engine is very complex and carries the greatest failure risk of all of the compressor package components. By continuing to comply with original equipment manufacturer (OEM) recommended Preventive Maintenance (PM) schedules and overhauls, compressor reliability risks are controlled to moderate levels. In the case of performing regular OEM prescribed overhauls, the risk of unit failure is proposed as a sawtooth function, whereby risk increases gradually over the recommended interval between overhauls and then drops suddenly after an overhaul. Critical internal wear components are on a path to failure and generally in sync with operating hours. If the operating hours are extended too far, the resulting additional operational stress on internal components, such as high temperature coatings and bearings, will increase the component scrap rate when performing the overhaul. This will add significant (10 to 20% or more) cost to the base overhaul and increases the risk of a random failure leading to system unreliability and further cost increases.** **Justification: Potential for unexpected or catastrophic failure if timing is extended.** **Assets: Avon serial 38148** **Related Investments: Not applicable.**	In Progress							

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Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Pass**		**48240**	Lobo A1 Gas Generator (38425) End-of-Life Overhaul	**2025**	$ 2,686,216	**Issue/Concern/Opportunity: The consequence of compressor failure is dominated by gas cost impacts to customers. The compressor package is comprised of a gas turbine engine driver, compressor, power turbine and ancillary equipment such as lube oil, fuel supply, and electronic control systems, which are required for the compressor to operate. The gas turbine engine is very complex and carries the greatest failure risk of all of the compressor package components. By continuing to comply with original equipment manufacturer (OEM) recommended Preventive Maintenance (PM) schedules and overhauls, compressor reliability risks are controlled to moderate levels. In the case of performing regular OEM prescribed overhauls, the risk of unit failure is proposed as a sawtooth function, whereby risk increases gradually over the recommended interval between overhauls and then drops suddenly after an overhaul. Critical internal wear components are on a path to failure and generally in sync with operating hours. If the operating hours are extended too far, the resulting additional operational stress on internal components, such as high temperature coatings and bearings, will increase the component scrap rate when performing the overhaul. This will add significant (10 to 20% or more) cost to the base overhaul and increases the risk of a random failure leading to system unreliability and further cost increases. Justification: Potential for unexpected or catastrophic failure if timing is extended. Asset: Avon serial 38425 Related Investments: Not applicable.**	In Progress							
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Pass**		**48715**	Dawn C Compression Lifecycle	**2026**	$ 163,382,650	**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 as the global inventory of spare components diminishes. Assets: Dawn Plant C**	In Progress							
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Pass**		**48732**	Waubuno Compression Lifecycle	**2025**	$ 20,113,719	**Issue/Concern/Opportunity: The Waubuno compressor elevates available pipeline pressure to the Waubuno Pool Maximum Operating Pressure (MOP). Compression increases the working inventory value of the pool by approximately3.5 PJ 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 usable 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 compressor out of service for at least one operational season. Assets: Waubuno Compressor Related Programs: N/A**	In Progress							
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Pass**		**48753**	Parkway C Gas Generator Midlife Overhaul	**2026**	$ 4,039,990	**Issue/Concern/Opportunity: The consequence of compressor failure is dominated by gas cost impacts to customers. The compressor package is comprised of a gas turbine engine driver, compressor, power turbine and ancillary equipment such as lube oil, fuel supply, and electronic control systems, which are required for the compressor to operate. The gas turbine engine is very complex and carries the greatest failure risk of all of the compressor package components. By continuing to comply with original equipment manufacturer (OEM) recommended Preventive Maintenance (PM) schedules and overhauls, compressor reliability risks are controlled to moderate levels. In the case of performing regular OEM prescribed overhauls, the risk of unit failure is proposed as a sawtooth function, whereby risk increases gradually over the recommended interval between overhauls and then drops suddenly after an overhaul. Critical internal wear components are on a path to failure and generally in sync with operating hours. If the operating hours are extended too far, the resulting additional operational stress on internal components, such as high temperature coatings and bearings, will increase the component scrap rate when performing the overhaul. This will add significant (10 to 20% or more) cost to the base overhaul and increases the risk of a random failure leading to system unreliability and further cost increases. Assets: Related Investments:**	In Progress							

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Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Pass**		**49954**	Avon 1534 Gas Generator (37433)End-of-Life Overhaul	**2026**	$ 2,710,703	**Issue/Concern/Opportunity: The consequence of compressor failure is dominated by gas cost impacts to customers. The compressor package is comprised of a gas turbine engine driver, compressor, power turbine and ancillary equipment such as lube oil, fuel supply, and electronic control systems, which are required for the compressor to operate. The gas turbine engine is very complex and carries the greatest failure risk of all of the compressor package components. By continuing to comply with original equipment manufacturer (OEM) recommended Preventive Maintenance (PM) schedules and overhauls, compressor reliability risks are controlled to moderate levels. In the case of performing regular OEM prescribed overhauls, the risk of unit failure is proposed as a sawtooth function, whereby risk increases gradually over the recommended interval between overhauls and then drops suddenly after an overhaul. Critical internal wear components are on a path to failure and generally in sync with operating hours. If the operating hours are extended too far, the resulting additional operational stress on internal components, such as high temperature coatings and bearings, will increase the component scrap rate when performing the overhaul. This will add significant (10 to 20% or more) cost to the base overhaul and increases the risk of a random failure leading to system unreliability and further cost increases.** **Justification: Extension of interval can result in unexpected or catastrophic failure** **Asset: 37433** **Related Investments: Not applicable.**	In Progress							
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Pass**		**49956**	Bright A1 Gas Generator - Mid life Overhaul	**2028**	$ 5,367,082	**Issue/Concern/Opportunity: The consequence of compressor failure is dominated by gas cost impacts to customers. The compressor package is comprised of a gas turbine engine driver, compressor, power turbine and ancillary equipment such as lube oil, fuel supply, and electronic control systems, which are required for the compressor to operate. The gas turbine engine is very complex and carries the greatest failure risk of all of the compressor package components. By continuing to comply with original equipment manufacturer (OEM) recommended Preventive Maintenance (PM) schedules and overhauls, compressor reliability risks are controlled to moderate levels. In the case of performing regular OEM prescribed overhauls, the risk of unit failure is proposed as a sawtooth function, whereby risk increases gradually over the recommended interval between overhauls and then drops suddenly after an overhaul. Critical internal wear components are on a path to failure and generally in sync with operating hours. If the operating hours are extended too far, the resulting additional operational stress on internal components, such as high temperature coatings and bearings, will increase the component scrap rate when performing the overhaul. This will add significant (10 to 20% or more) cost to the base overhaul and increases the risk of a random failure leading to system unreliability and further cost increases.** **Justification: Extension of interval can result in unexpected or catastrophic failure.** **Assets: RB211-G DLE 1790-863** **Related Investments: Not applicable.**	In Progress							
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Pass**		**49958**	Bright B Gas Generator End-of-Life Overhaul	**2025**	$ 4,003,496	**Issue/Concern/Opportunity: The consequence of compressor failure is dominated by gas cost impacts to customers. The compressor package is comprised of a gas turbine engine driver, compressor, power turbine and ancillary equipment such as lube oil, fuel supply, and electronic control systems, which are required for the compressor to operate. The gas turbine engine is very complex and carries the greatest failure risk of all of the compressor package components. By continuing to comply with original equipment manufacturer (OEM) recommended Preventive Maintenance (PM) schedules and overhauls, compressor reliability risks are controlled to moderate levels. In the case of performing regular OEM prescribed overhauls, the risk of unit failure is proposed as a sawtooth function, whereby risk increases gradually over the recommended interval between overhauls and then drops suddenly after an overhaul. Critical internal wear components are on a path to failure and generally in sync with operating hours. If the operating hours are extended too far, the resulting additional operational stress on internal components, such as high temperature coatings and bearings, will increase the component scrap rate when performing the overhaul. This will add significant (10 to 20% or more) cost to the base overhaul and increases the risk of a random failure leading to system unreliability and further cost increases.** **Justification: Extension of interval can result in unexpected or catastrophic failure.** **Assets: Bright B RB211-24C** **Related Investments: Not applicable.**	In Progress							
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Pass**		**49965**	Dawn F2 Gas Producer Overhaul	**2025**	$ 2,149,800	**Issue/Concern/Opportunity: The consequence of compressor failure is dominated by gas cost impacts to customers. The compressor package is comprised of a gas turbine engine driver, compressor, power turbine and ancillary equipment such as lube oil, fuel supply, and electronic control systems, which are required for the compressor to operate. The gas turbine engine is very complex and carries the greatest failure risk of all of the compressor package components. By continuing to comply with original equipment manufacturer (OEM) recommended Preventive Maintenance (PM) schedules and overhauls, compressor reliability risks are controlled to moderate levels. In the case of performing regular OEM prescribed overhauls, the risk of unit failure is proposed as a saw tooth function, whereby risk increases gradually over the recommended interval between overhauls and then drops suddenly after an overhaul. Critical internal wear components are on a path to failure and generally in sync with operating hours. If the operating hours are extended too far, the resulting additional operational stress on internal components, such as high temperature coatings and bearings, will increase the component scrap rate when performing the overhaul. This will add significant (10 to 20 per cent or more) cost to the base overhaul and increases the risk of a random failure leading to system unreliability and further cost increases.** **Justification: Extension of interval can result in unexpected or catastrophic failure** **Asset: Taurus 70- TC06299/OHC15-B3953** **Related Investments: Not applicable.**	In Progress							
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Pass**		**100948**	Dawn: 5985 CV & Piping - Improvements	**2023**	$ 2,327,024	**Issue/Concern/Opportunity: Flow control to and from the Dawn 5985 pool consists of a high-flow and low-flow control valve run. Flow dynamic of natural gas out of this critical supply high deliverability pool into the Dawn Yard has changed over the years such that the flow regime during normal non-peak day operations falls greater than the capability of the low-flow control valve run but at the very low end of the large control valve flow run. The high-flow control valve is an older style ball Fisher type valve which does not work efficiently at low flows. Extreme noise is created, over the 100 dB level, resulting in high cycle vibration of the valve internals leading to premature failure. A failure occurred in 2019 whereupon a clanging noise was being produced. The valves were removed and examined by Fisher. The large diameter valve was found to be excessively worn. Fisher rebuilt the large diameter valve after which it was reinstalled in order to place the 5985 pool back in service. Fisher's recommendation is that EGI avoids operating the large diameter valve under these conditions.** **Assets: Control valves (CV 12 and CV 20)** **Related Investments: Not applicable.**	Planned							

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STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Pass**		**733780**	Dawn D Gas Generator - Mid life Overhaul	**2024**	$ 2,772,130	**Issue/Concern/Opportunity: The consequence of compressor failure is dominated by gas cost impacts to customers. The compressor package is comprised of a gas turbine engine driver, compressor, power turbine and ancillary equipment such as lube oil, fuel supply, and electronic control systems, which are required for the compressor to operate. The gas turbine engine is very complex and carries the greatest failure risk of all of the compressor package components. By continuing to comply with original equipment manufacturer (OEM) recommended Preventive Maintenance (PM) schedules and overhauls, compressor reliability risks are controlled to moderate levels. In the case of performing regular OEM prescribed overhauls, the risk of unit failure is proposed as a sawtooth function, whereby risk increases gradually over the recommended interval between overhauls and then drops suddenly after an overhaul. Critical internal wear components are on a path to failure and generally in sync with operating hours. If the operating hours are extended too far, the resulting additional operational stress on internal components, such as high temperature coatings and bearings, will increase the component scrap rate when performing the overhaul. This will add significant (10 to 20% or more) cost to the base overhaul and increases the risk of a random failure leading to system unreliability and further cost increases. Justification: Extension of interval can result in unexpected or catastrophic failure. Assets: RB211-G DLE 1790-864 Related Investments: Not applicable.**	In Progress							
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Pass**		**734634**	Dawn to Corunna (Dawn Tie-in)	**2023**	$ 47,886,299	**Issue/Concern/Opportunity: EGI recognizes its obligation to meet the firm demands of its customers; and as a result, assets are continually evaluated to identify hazards and to assess risks in order to ensure that they remain reliable, suitable, and fit for continued service. To this end, an Asset Health Review (AHR) was performed in 2018 and updated in 2021 as part of the Company's comprehensive Reliability, Availability and Maintainability (RAM) Study for the Corunna Compressor Station (CCS), which was completed by a consultant. The results of this study indicate that the health and maintainability of certain compressor units at the CCS are in decline. Reasons for this decline include, but are not limited to performance, functional issues with custom components (i.e., spare parts), and wear. As a result of these assessments, the Company has identified serious and increasing obsolescence and reliability risks associated with certain CCS compressor units and is experiencing a need for increased maintenance and repair work to keep the units operational going forward. Further, as a result of the compressor units' obsolescence and reliability issues, the Company has experienced continued and increasing compressor unit downtime and long lead repair time. This has created a need for increased maintenance and repair work performed by EGI personnel at the CCS. EGI has also undertaken comprehensive studies, including a site-wide quantitative risk assessment (QRA) to determine the severity of the increasing safety risks, and has determined that the current configuration of compressor units (which includes multiple compressor units in close proximity within a single building), results in an excessive level of process safety risk. Assets: Compressors K701, K702, K703, K705, K706, K707 and K708 Related Investments: 100901 - Dawn to Corunna**	In Progress							
STO - UG	**Div_53 - Union South Storage**	Compression Stations	**Pass**		**735801**	Parkway D Gas Generator Midlife Overhaul	**2032**	$ 4,209,773	**Issue/Concern/Opportunity: The consequence of compressor failure is dominated by gas cost impacts to customers. The compressor package is comprised of a gas turbine engine driver, compressor, power turbine and ancillary equipment such as lube oil, fuel supply, and electronic control systems, which are required for the compressor to operate. The gas turbine engine is very complex and carries the greatest failure risk of all of the compressor package components. By continuing to comply with original equipment manufacturer (OEM) recommended Preventive Maintenance (PM) schedules and overhauls, compressor reliability risks are controlled to moderate levels. In the case of performing regular OEM prescribed overhauls, the risk of unit failure is proposed as a sawtooth function, whereby risk increases gradually over the recommended interval between overhauls and then drops suddenly after an overhaul. Critical internal wear components are on a path to failure and generally in sync with operating hours. If the operating hours are extended too far, the resulting additional operational stress on internal components, such as high temperature coatings and bearings, will increase the component scrap rate when performing the overhaul. This will add significant (10 to 20% or more) cost to the base overhaul and increases the risk of a random failure leading to system unreliability and further cost increases. Assets: Related Investments:**	In Progress							
STO - UG	**Div_53 - Union South Storage**	LNG	**Pass**		**48714**	Hagar Cold Box	**2032**	$ 15,041,122	**Issue/Concern: The Cold Box is several heat exchangers in series used to cool the natural gas feedstock to -160°C at which point the natural gas turns into a liquid. The Cold Box is the core of the liquefied natural gas (LNG) station and is necessary to produce LNG. The consequence of a Cold Box failure is dominated by customer impact. Risk of associated failure is heavily influenced by thermal cycling and operational hours. Over its 50 years of operation, the Cold Box has amassed 140,000 operational hours. Significant failure modes include leakage of natural gas or refrigerants out of the piping into the interior of the Cold Box shell reaching potentially explosive levels or heat exchanger cross leaks that reduce the effectiveness of the refrigeration process. Both of these failure modes impair LNG production to the extent the plant cannot meet its annual production requirements. As the Cold Box internals are encased in very densely packed insulation and clad in an outer steel jacket, troubleshooting and repair of either of these failure modes is extremely difficult and time consuming. Assets: Cold Box Related Programs: Not applicable**	Complete	**Fail**	See investment description, IRPAs not appliable					
STO - UG	**Div_53 - Union South Storage**	Transmission Pipe & Underground Storage	**Fail**	Dollar threshold	**1270**	Oil City Retrofit		$ 313,874									
STO - UG	**Div_53 - Union South Storage**	Transmission Pipe & Underground Storage	**Fail**	Dollar threshold	**1271**	NPS 10 Sombra Line ILI Retrofit		$ 308,891									
STO - UG	**Div_53 - Union South Storage**	Transmission Pipe & Underground Storage	**Fail**	Dollar threshold	**1784**	Panhandle NPS 16 - Bradley Line Class Location Replacement		$ 1,494,636									
STO - UG	**Div_53 - Union South Storage**	Transmission Pipe & Underground Storage	**Fail**	Dollar threshold	**48708**	Gas Chromatograph Replacement*	**2021**	$ 602,658									
STO - UG	**Div_53 - Union South Storage**	Transmission Pipe & Underground Storage	**Fail**	Dollar threshold	**100533**	Wellhead Upgrade Project	**2024**	$ 451,601									
STO - UG	**Div_53 - Union South Storage**	Transmission Pipe & Underground Storage	**Fail**	Dollar threshold	**100769**	Well Protection Improvements - Lock Blocks and Fences	**2021**	$ 1,009,415									
STO - UG	**Div_53 - Union South Storage**	Transmission Pipe & Underground Storage	**Fail**	Dollar threshold	**102417**	Rectifier Ground Bed Replacement Program*	**2021**	$ 1,240,385									
STO - UG	**Div_53 - Union South Storage**	Transmission Pipe & Underground Storage	**Fail**	Dollar threshold	**102528**	Well Optimization Program 2023*	**2023**	$ 311,383									

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STO - UG	Div_53 - Union South Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	102529	Well Optimization Program 2024*	2024	$ 320,405									
STO - UG	Div_53 - Union South Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	102530	Well Optimization Program 2025*	2025	$ 322,863									
STO - UG	Div_53 - Union South Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	102531	Well Optimization Program 2026*	2026	$ 325,806									
STO - UG	Div_53 - Union South Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	102532	Well Optimization Program 2027*	2027	$ 346,936									
STO - UG	Div_53 - Union South Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	102533	Well Optimization Program 2028*	2028	$ 344,044									
STO - UG	Div_53 - Union South Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	102535	Well Optimization Program 2029*	2029	$ 341,580									
STO - UG	Div_53 - Union South Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	102536	Well Optimization Program 2030*	2030	$ 353,687									
STO - UG	Div_53 - Union South Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	102561	STO STORAGE WELL UPGRADES 2023*	2023	$ 267,789									
STO - UG	Div_53 - Union South Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	102562	STO STORAGE WELL UPGRADES 2024*	2024	$ 275,548									
STO - UG	Div_53 - Union South Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	102563	STO STORAGE WELL UPGRADES 2025*	2025	$ 277,662									
STO - UG	Div_53 - Union South Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	102564	STO STORAGE WELL UPGRADES 2026*	2026	$ 423,547									
STO - UG	Div_53 - Union South Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	102565	STO STORAGE WELL UPGRADES 2027*	2027	$ 451,016									
STO - UG	Div_53 - Union South Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	102567	STO STORAGE WELL UPGRADES 2028*	2028	$ 447,257									
STO - UG	Div_53 - Union South Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	102568	STO STORAGE WELL UPGRADES 2029*	2029	$ 444,054									
STO - UG	Div_53 - Union South Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	102569	STO STORAGE WELL UPGRADES 2030*	2030	$ 459,794									
STO - UG	Div_53 - Union South Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	503062	Atmospheric Storage Tank Level Instrumentation 2023*		$ 61,654									
STO - UG	Div_53 - Union South Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	503064	Atmospheric Storage Tank Level Instrumentation 2024*		$ 63,440									
STO - UG	Div_53 - Union South Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	503066	Atmospheric Storage Tank Level Instrumentation 2025*		$ 63,927									
STO - UG	Div_53 - Union South Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	733613	NPS 10 Bentpath East - Booth Creek Retrofit		$ 1,464,367									
STO - UG	Div_53 - Union South Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	733830	NPS 10 Oil City Pool Retrofit		$ 463,337									
STO - UG	Div_53 - Union South Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	734280	Ultrasonic Meter Upgrade 2023*		$ 398,570									
STO - UG	Div_53 - Union South Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	734281	Ultrasonic Meter Upgrade 2024*		$ 410,118									
STO - UG	Div_53 - Union South Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	734891	Bentpath Pool Gathering System		$ 671,554									
STO - UG	Div_53 - Union South Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	734893	Rosedale Pool Gathering System		$ 736,127									
STO - UG	Div_53 - Union South Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	734896	Bickford Pool Gathering System 2027 ECDA to ILI		$ 791,013									
STO - UG	Div_53 - Union South Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	734923	Oil Springs East Gathering System		$ 873,159									
STO - UG	Div_53 - Union South Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	735404	Well Optimization Program 2031*	2031	$ 349,820									
STO - UG	Div_53 - Union South Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	735405	Well Optimization Program 2032*	2032	$ 339,498									
STO - UG	Div_53 - Union South Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	735417	STO STORAGE WELL UPGRADES 2031*	2031	$ 454,766									
STO - UG	Div_53 - Union South Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	735418	STO STORAGE WELL UPGRADES 2032*	2032	$ 441,347									
STO - UG	Div_53 - Union South Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	735747	Ennisksillen Well Laterals Retrofit		$ 1,026,703									
STO - UG	Div_53 - Union South Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	735748	Booth Creek Pool Retrofit		$ 1,103,504									
STO - UG	Div_53 - Union South Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	735749	Mandaumin Pool Line Retrofit	2031	$ 1,679,134									
STO - UG	Div_53 - Union South Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	735994	Oil City A1 Observation Well	2025	$ 1,576,614									
STO - UG	Div_53 - Union South Storage	Transmission Pipe & Underground Storage	Fail	Dollar threshold	736098	New Well Lateral/Crossover (Well Lifecycle Replacement)*	2020	$ 1,304,613									

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STO - UG	**Div_53 - Union South Storage**	Transmission Pipe & Underground Storage	**Fail**	Dollar threshold	**736408**	156 Storage Pool Gathering System Retrofits		$ 437,139									
STO - UG	**Div_53 - Union South Storage**	Transmission Pipe & Underground Storage	**Fail**	Dollar threshold	**736651**	Mandaumin A1 observation well	**2024**	$ 1,416,750									
STO - UG	**Div_53 - Union South Storage**	Transmission Pipe & Underground Storage	**Fail**	Timing	**1277**	2023 Well Lateral Integrity Program*	**2023**	$ 4,982,120				Within 3 years, supply side not applicable					
STO - UG	**Div_53 - Union South Storage**	Transmission Pipe & Underground Storage	**Fail**	Timing	**1279**	2023 Integrity Dig Program S&T*	**2023**	$ 3,051,549				Within 3 years, supply side not applicable					
STO - UG	**Div_53 - Union South Storage**	Transmission Pipe & Underground Storage	**Fail**	Timing	**1283**	2024 Well Lateral Integrity Program*	**2024**	$ 5,126,473				Within 3 years, supply side not applicable					
STO - UG	**Div_53 - Union South Storage**	Transmission Pipe & Underground Storage	**Fail**	Timing	**1286**	2024 Depth of Cover Mitigation Program*	**2024**	$ 2,563,237				Within 3 years, supply side not applicable					
STO - UG	**Div_53 - Union South Storage**	Transmission Pipe & Underground Storage	**Fail**	Timing	**1288**	2024 Integrity Dig Program S&T*	**2024**	$ 7,016,860				Within 3 years, supply side not applicable					
STO - UG	**Div_53 - Union South Storage**	Transmission Pipe & Underground Storage	**Fail**	Timing	**1293**	2025 Depth of Cover Mitigation Program*	**2025**	$ 3,260,663				Within 3 years, supply side not applicable					
STO - UG	**Div_53 - Union South Storage**	Transmission Pipe & Underground Storage	**Fail**	Timing	**1295**	2025 Integrity Dig Program S&T*	**2025**	$ 3,616,059				Within 3 years, supply side not applicable					
STO - UG	**Div_53 - Union South Storage**	Transmission Pipe & Underground Storage	**Fail**	Timing	**1296**	2025 Well Lateral Integrity Program*	**2025**	$ 4,429,673				Within 3 years, supply side not applicable					
STO - UG	**Div_53 - Union South Storage**	Transmission Pipe & Underground Storage	**Fail**	Timing	**736365**	A1 Observation Well Program*	**2022**	$ 9,031,716				Within 3 years, supply side not applicable					
STO - UG	**Div_53 - Union South Storage**	Transmission Pipe & Underground Storage	**Pass**		**48257**	INTE: Dawn - Cuthbert - NPS 42 replacement	**2022**	$ 626,339	**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% SMYS. It includes installation costs for a 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 repair and replacement of pipeline segments with integrity issues that are identified through the inspections.** **Project-Specific Concern: The NPS 42, NPS 34, and NPS 26 pipelines between Dawn Compressor Station and Cuthbert Road receiver site have been inspected using external corrosion direct assessment (ECDA). Although it meets the intent of the Transmission Integrity Management Program (TIMP), there are specific features that ECDA could not detect comparing to the ILI. ILI of these transmission lines is required to ensure continued safety and reliability of EGI's assets.** **Assets: Transmission Pipeline (NPS 42, NPS 34, and NPS 26 pipelines between Dawn Compressor Station and Cuthbert Road receiver site)** **Related Programs: TIMP**	Planned							
STO - UG	**Div_53 - Union South Storage**	Transmission Pipe & Underground Storage	**Pass**		**48258**	INTE: Dawn - Cuthbert - ECDA to ILI Retrofit NPS 34*	**2022**	$ 143,402	**Project-Specific: External Corrosion Direct Assessment (ECDA) to In-Line Inspection (ILI) retrofit of NPS 34 pipeline between Dawn Compressor station and Cuthbert Road receiver site.** **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% Specified Minimum Yield Strength (SMYS). It includes installation costs for permanent 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 that are identified through the inspections**	Complete	**Fail**	See investment description, IRPAs not appliable					
STO - UG	**Div_53 - Union South Storage**	Transmission Pipe & Underground Storage	**Pass**		**48259**	INTE: Dawn - Cuthbert - ECDA to ILI Retrofit NPS 26	**2022**	$ 75,062	**Project-Specific: External Corrosion Direct Assessment (ECDA) to In-Line Inspection (ILI) retrofit of NPS 26 pipeline between Dawn Compressor station and Cuthbert Road receiver site.** **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% Specified Minimum Yield Strength (SMYS). It includes installation costs for permanent 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 that are identified through the inspections.**	Complete	**Fail**	See investment description, IRPAs not appliable					
STO - UG	**Div_53 - Union South Storage**	Transmission Pipe & Underground Storage	**Pass**		**48735**	Well Lifecycle Replacement	**2032**	$ 14,292,296	**Issue/Concern: This project is intended to recover lost design day deliverability due to well relines and abandonments. The deliverability of the new well is not intended to increase but maintain the deliverability. This project will drill one new vertical injection/withdrawal well and connect it to the existing gathering system of the desired pool.** **Asset: Wells** **Related Program: N/A**	Planned							
STO - UG	**Div_53 - Union South Storage**	Transmission Pipe & Underground Storage	**Pass**		**102573**	MOP Verification Replacement Program 2025 - S&T Assets*	**2030**	$ 1,291,450	**General: MOP verification is the process of reviewing all existing records for a pipeline system and confirming the maximum operating pressure of existing greater than 30 per cent SMYS pipeline systems based upon these records. While this is not currently mandated by code in Canada, it is required in the U.S. and is expected to become a requirement in Canada in the future. Given the number of pipelines greater than 30 per cent SMYS, MOP Verification will be a multi-year project requiring a dedicated team to complete the verifications and determine if any pipeline remediation is required. This forecast includes the costs of replacing sections of pipelines as identified through the MOP verification work. MOP verification was also included in the 2017 customer engagement survey: while 43 per cent of those surveyed recommend waiting for regulation requirements to keep costs down, 40 per cent recommend proactively implementing industry standard. Spreading the verifications over several years will keep costs down and proactively implement an industry standard, which provides additional support for this program. Starting this program as forecast will mitigate the need for higher expenditures in a shorter time frame to meet these expected future mandated requirements.**	Complete	**Fail**	See investment description, IRPAs not appliable					
STO - UG	**Div_53 - Union South Storage**	Transmission Pipe & Underground Storage	**Pass**		**102772**	2026 Integrity Dig Program S&T*		$ 4,346,248	**2026 forecast: This is a program budget placeholder, estimated using an average of the spend profile between 2021-2025** **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 inline 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 that are identified through the inspections.**	Complete	**Fail**	See investment description, IRPAs not appliable					

* in the Investment Name indicates a program item. Program items are unique as they represent numerous projects grouped together and budgeted in advance. This results in forecast spend appearing larger than it would at the project level and it also impacts the in-service dates

Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
STO - UG	**Div_53 - Union South Storage**	Transmission Pipe & Underground Storage	**Pass**		**102773**	2027 Integrity Dig Program S&T*		$ 4,628,123	**2027 forecast: This is a program budget placeholder, estimated using an average of the spend profile between 2021-2025 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 inline 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 that are identified through the inspections.**	Complete	**Fail**	See investment description, IRPAs not appliable					
STO - UG	**Div_53 - Union South Storage**	Transmission Pipe & Underground Storage	**Pass**		**102774**	2028 Integrity Dig Program S&T*		$ 4,589,543	**2028 forecast: This is a program budget placeholder, estimated using an average of the spend profile between 2021-2025 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 inline 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 that are identified through the inspections.**	Complete	**Fail**	See investment description, IRPAs not appliable					
STO - UG	**Div_53 - Union South Storage**	Transmission Pipe & Underground Storage	**Pass**		**102775**	2029 Integrity Dig Program S&T*		$ 4,556,681	**2029 forecast: This is a program budget placeholder, estimated using an average of the spend profile between 2021-2025 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 inline 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 that are identified through the inspections.**	Complete	**Fail**	See investment description, IRPAs not appliable					
STO - UG	**Div_53 - Union South Storage**	Transmission Pipe & Underground Storage	**Pass**		**102776**	2030 Integrity Dig Program S&T*		$ 4,718,189	**2030 forecast: This is a program budget placeholder, estimated using an average of the spend profile between 2021-2025 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 inline 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 that are identified through the inspections.**	Complete	**Fail**	See investment description, IRPAs not appliable					
STO - UG	**Div_53 - Union South Storage**	Transmission Pipe & Underground Storage	**Pass**		**102777**	2026 Depth of Cover Mitigation Program*		$ 4,289,775	**2026 forecast: This is a program budget placeholder, estimated using an average of the spend profile between 2021-2025 Mitigation of depth of cover sites that are out of compliance with CSA Z662 & TSSA requirements. Some of the known sites are discovered during annual Depth of Cover Surveying, while others are reported by company crews when performing maintenance work or by 3rd party . At this time the specific work scope of each year is not defined and this is a blanket program as a placeholder in the budget. The mitigation work will include the construction costs from sites identified and planned for the current year, as well as work on sites that are newly identified. Scope of work can vary from small remediation projects to add fill, concrete or bank stabilization, to short replacement of pipe.**	Complete	**Fail**	See investment description, IRPAs not appliable					
STO - UG	**Div_53 - Union South Storage**	Transmission Pipe & Underground Storage	**Pass**		**102778**	2027 Depth of Cover Mitigation Program*		$ 4,567,988	**2027 forecast: This is a program budget placeholder, estimated using an average of the spend profile between 2021-2025 Mitigation of depth of cover sites that are out of compliance with CSA Z662 & TSSA requirements. Some of the known sites are discovered during annual Depth of Cover Surveying, while others are reported by company crews when performing maintenance work or by 3rd party . At this time the specific work scope of each year is not defined and this is a blanket program as a placeholder in the budget. The mitigation work will include the construction costs from sites identified and planned for the current year, as well as work on sites that are newly identified. Scope of work can vary from small remediation projects to add fill, concrete or bank stabilization, to short replacement of pipe.**	Complete	**Fail**	See investment description, IRPAs not appliable					
STO - UG	**Div_53 - Union South Storage**	Transmission Pipe & Underground Storage	**Pass**		**102779**	2028 Depth of Cover Mitigation Program*		$ 4,529,910	**2028 forecast: This is a program budget placeholder, estimated using an average of the spend profile between 2021-2025 Mitigation of depth of cover sites that are out of compliance with CSA Z662 & TSSA requirements. Some of the known sites are discovered during annual Depth of Cover Surveying, while others are reported by company crews when performing maintenance work or by 3rd party . At this time the specific work scope of each year is not defined and this is a blanket program as a placeholder in the budget. The mitigation work will include the construction costs from sites identified and planned for the current year, as well as work on sites that are newly identified. Scope of work can vary from small remediation projects to add fill, concrete or bank stabilization, to short replacement of pipe.**	Complete	**Fail**	See investment description, IRPAs not appliable					
STO - UG	**Div_53 - Union South Storage**	Transmission Pipe & Underground Storage	**Pass**		**102781**	2029 Depth of Cover Mitigation Program*		$ 4,497,474	**2029 forecast: This is a program budget placeholder, estimated using an average of the spend profile between 2021-2025 Mitigation of depth of cover sites that are out of compliance with CSA Z662 & TSSA requirements. Some of the known sites are discovered during annual Depth of Cover Surveying, while others are reported by company crews when performing maintenance work or by 3rd party . At this time the specific work scope of each year is not defined and this is a blanket program as a placeholder in the budget. The mitigation work will include the construction costs from sites identified and planned for the current year, as well as work on sites that are newly identified. Scope of work can vary from small remediation projects to add fill, concrete or bank stabilization, to short replacement of pipe.**	Complete	**Fail**	See investment description, IRPAs not appliable					
STO - UG	**Div_53 - Union South Storage**	Transmission Pipe & Underground Storage	**Pass**		**102782**	2030 Depth of Cover Mitigation Program*		$ 4,656,884	**2030 forecast: This is a program budget placeholder, estimated using an average of the spend profile between 2021-2025 Mitigation of depth of cover sites that are out of compliance with CSA Z662 & TSSA requirements. Some of the known sites are discovered during annual Depth of Cover Surveying, while others are reported by company crews when performing maintenance work or by 3rd party . At this time the specific work scope of each year is not defined and this is a blanket program as a placeholder in the budget. The mitigation work will include the construction costs from sites identified and planned for the current year, as well as work on sites that are newly identified. Scope of work can vary from small remediation projects to add fill, concrete or bank stabilization, to short replacement of pipe.**	Complete	**Fail**	See investment description, IRPAs not appliable					
STO - UG	**Div_53 - Union South Storage**	Transmission Pipe & Underground Storage	**Pass**		**102783**	2026 Well Lateral Integrity Program*		$ 3,905,325	**2026 forecast: This is a program budget placeholder, estimated using an average of the spend profile between 2023-2025 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. Expenditure included in this category is for pipelines that operate above 30 per cent SMYS. It includes installation costs for retrofits to existing lines to remove restrictive fittings or pipe configurations so they can be inspected with ILI tools or subject to other integrity verification.**	Complete	**Fail**	See investment description, IRPAs not appliable					
STO - UG	**Div_53 - Union South Storage**	Transmission Pipe & Underground Storage	**Pass**		**102784**	2027 Well Lateral Integrity Program*		$ 4,651,252	**2027 forecast: This is a program budget placeholder, estimated using an average of the spend profile between 2023-2025 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. Expenditure included in this category is for pipelines that operate above 30 per cent SMYS. It includes installation costs for retrofits to existing lines to remove restrictive fittings or pipe configurations so they can be inspected with ILI tools or subject to other integrity verification.**	Complete	**Fail**	See investment description, IRPAs not appliable					
STO - UG	**Div_53 - Union South Storage**	Transmission Pipe & Underground Storage	**Pass**		**102785**	2028 Well Lateral Integrity Program*		$ 5,045,975	**2028 forecast: This is a program budget placeholder, estimated using an average of the spend profile between 2023-2025 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. Expenditure included in this category is for pipelines that operate above 30 per cent SMYS. It includes installation costs for retrofits to existing lines to remove restrictive fittings or pipe configurations so they can be inspected with ILI tools or subject to other integrity verification.**	Complete	**Fail**	See investment description, IRPAs not appliable					

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Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
STO - UG	Div_53 - Union South Storage	Transmission Pipe & Underground Storage	Pass		102786	2029 Well Lateral Integrity Program*		$ 5,009,845	2029 forecast: This is a program budget placeholder, estimated using an average of the spend profile between 2023-2025 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. Expenditure included in this category is for pipelines that operate above 30 per cent SMYS. It includes installation costs for retrofits to existing lines to remove restrictive fittings or pipe configurations so they can be inspected with ILI tools or subject to other integrity verification.	Complete	Fail	See investment description, IRPAs not appliable					
STO - UG	Div_53 - Union South Storage	Transmission Pipe & Underground Storage	Pass		102787	2030 Well Lateral Integrity Program*		$ 4,083,910	2030 forecast: This is a program budget placeholder, estimated using an average of the spend profile between 2023-2025 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. Expenditure included in this category is for pipelines that operate above 30 per cent SMYS. It includes installation costs for retrofits to existing lines to remove restrictive fittings or pipe configurations so they can be inspected with ILI tools or subject to other integrity verification.	Complete	Fail	See investment description, IRPAs not appliable					
STO - UG	Div_53 - Union South Storage	Transmission Pipe & Underground Storage	Pass		102801	MOP Verification Replacement Program 2026 - S&T Assets*	2031	$ 2,606,446	General: MOP verification is the process of reviewing all existing records for a pipeline system and confirming the maximum operating pressure of existing greater than 30 per cent SMYS pipeline systems based upon these records. While this is not currently mandated by code in Canada, it is required in the U.S. and is expected to become a requirement in Canada in the future. Given the number of pipelines greater than 30 per cent SMYS, MOP Verification will be a multi-year project requiring a dedicated team to complete the verifications and determine if any pipeline remediation is required. This forecast includes the costs of replacing sections of pipelines as identified through the MOP verification work. MOP verification was also included in the 2017 customer engagement survey: while 43 per cent of those surveyed recommend waiting for regulation requirements to keep costs down, 40 per cent recommend proactively implementing industry standard. Spreading the verifications over several years will keep costs down and proactively implement an industry standard, which provides additional support for this program. Starting this program as forecast will mitigate the need for higher expenditures in a shorter time frame to meet these expected future mandated requirements.	Complete	Fail	See investment description, IRPAs not appliable					
STO - UG	Div_53 - Union South Storage	Transmission Pipe & Underground Storage	Pass		503024	2024 Waubuno 2 replacement wells	2024	$ 5,322,148	Issue: The deliverability of the Waubuno pool has declined due to the relines of the injection withdrawal wells UI20, UM20, UI22 and UI25 as well as the abandonment of the well UI30. The well UI20 is in a flood plain which is inaccessible during the spring months. Any response to a well incident would be severely impacted by the condition of the well and access to the well. The proposed abandonment of this will reduce deliverability. This project drills abandoned one well UI20 and drills two 8 5/8-inch wells. The two new wells will offset the reduction of deliverability due to the relines and abandonments. Assets: Waubuno pool and Gathering lines Related Program: Not applicable.	Planned							
STO - UG	Div_53 - Union South Storage	Transmission Pipe & Underground Storage	Pass		503069	Dow A McPlank Connection	2024	$ 2,632,571	Issue/Concern/Opportunity: The Dow A pool is currently used to supply gas to the Sarnia market. Current Sarnia design day models assume that the Dow A pool is being completely drained. However, the Dow A pool can only be utilized until the pool reaches 700 psig without running the compressor. The purpose of this project is to tie Dow A into a lower pressure distribution line so that the inventory below 700 psi can be utilized without requiring compression. Assets: A new pipeline from Dow A Compression Station to McPlank distribution Related Program: Not applicable	Planned							
STO - UG	Div_53 - Union South Storage	Transmission Pipe & Underground Storage	Pass		503195	NPS 24 Trafalgar Bypass Retrofit	2023	$ 2,491,061	Issue/Concern/Opportunity: The NPS 24 Trafalgar Bypass pipeline connects the NPS 26 Trafalgar pipeline to Kirkwall Custody Transfer Station. The length is approximately 1.1 km. This pipeline's condition is currently monitored via External Corrosion Direct Assessment (ECDA), which does not provide as complete a data set as In-Line Inspection (ILI) for Integrity Management purposes. By inspecting the pipeline via ILI, the condition of the asset will be more fully understood and the asset risk profile defined and managed in accordance with company standard. Justification: Move pipeline Condition Monitoring from ECDA to ILI in order to provide more complete data for Integrity Management purposes. Assets: NPS 24 Trafalgar Bypass Pipeline; Kirkwall Custody Transfer Station. Related Investments: 2024 Operations and Maintenance (O&M) budget for in-line inspection.	Complete	Fail	See investment description, IRPAs not appliable					
STO - UG	Div_53 - Union South Storage	Transmission Pipe & Underground Storage	Pass		734057	2031 Integrity Dig Program S&T*		$ 4,666,594	2030 forecast: This is a program budget placeholder, estimated using an average of the spend profile between 2021-2025 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 inline 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 that are identified through the inspections.	Complete	Fail	See investment description, IRPAs not appliable					
STO - UG	Div_53 - Union South Storage	Transmission Pipe & Underground Storage	Pass		734058	2032 Integrity Dig Program S&T*		$ 4,528,901	2030 forecast: This is a program budget placeholder, estimated using an average of the spend profile between 2021-2025 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 inline 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 that are identified through the inspections.	Complete	Fail	See investment description, IRPAs not appliable					
STO - UG	Div_53 - Union South Storage	Transmission Pipe & Underground Storage	Pass		735413	2031 Depth of Cover Mitigation Program*		$ 4,605,959	2031 forecast: This is a program budget placeholder, estimated using an average of the spend profile between 2021-2025 Mitigation of depth of cover sites that are out of compliance with CSA Z662 & TSSA requirements. Some of the known sites are discovered during annual Depth of Cover Surveying, while others are reported by company crews when performing maintenance work or by 3rd party . At this time the specific work scope of each year is not defined and this is a blanket program as a placeholder in the budget. The mitigation work will include the construction costs from sites identified and planned for the current year, as well as work on sites that are newly identified. Scope of work can vary from small remediation projects to add fill, concrete or bank stabilization, to short replacement of pipe.	Complete	Fail	See investment description, IRPAs not appliable					
STO - UG	Div_53 - Union South Storage	Transmission Pipe & Underground Storage	Pass		735414	2032 Depth of Cover Mitigation Program*		$ 4,470,055	2032 forecast: This is a program budget placeholder, estimated using an average of the spend profile between 2021-2025 Mitigation of depth of cover sites that are out of compliance with CSA Z662 & TSSA requirements. Some of the known sites are discovered during annual Depth of Cover Surveying, while others are reported by company crews when performing maintenance work or by 3rd party . At this time the specific work scope of each year is not defined and this is a blanket program as a placeholder in the budget. The mitigation work will include the construction costs from sites identified and planned for the current year, as well as work on sites that are newly identified. Scope of work can vary from small remediation projects to add fill, concrete or bank stabilization, to short replacement of pipe.	Complete	Fail	See investment description, IRPAs not appliable					

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Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
STO - UG	**Div_53 - Union South Storage**	Transmission Pipe & Underground Storage	**Pass**		**735415**	2031 Well Lateral Integrity Program*		$ 5,130,689	**2031 forecast: This is a program budget placeholder, estimated using an average of the spend profile between 2023-2025 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. Expenditure included in this category is for pipelines that operate above 30 per cent SMYS. It includes installation costs for retrofits to existing lines to remove restrictive fittings or pipe configurations so they can be inspected with ILI tools or subject to other integrity verification.**	Complete	**Fail**	See investment description, IRPAs not appliable					
STO - UG	**Div_53 - Union South Storage**	Transmission Pipe & Underground Storage	**Pass**		**735416**	2032 Well Lateral Integrity Program*		$ 4,979,302	**2032 forecast: This is a program budget placeholder, estimated using an average of the spend profile between 2023-2025 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. Expenditure included in this category is for pipelines that operate above 30 per cent SMYS. It includes installation costs for retrofits to existing lines to remove restrictive fittings or pipe configurations so they can be inspected with ILI tools or subject to other integrity verification.**	Complete	**Fail**	See investment description, IRPAs not appliable					
STO - UG	**Div_53 - Union South Storage**	Transmission Pipe & Underground Storage	**Pass**		**735427**	MOP Verification Replacement Program 2027 - S&T Assets*	**2032**	$ 2,775,486	**General: MOP verification is the process of reviewing all existing records for a pipeline system and confirming the maximum operating pressure of existing greater than 30 per cent SMYS pipeline systems based upon these records. While this is not currently mandated by code in Canada, it is required in the U.S. and is expected to become a requirement in Canada in the future. Given the number of pipelines greater than 30 per cent SMYS, MOP Verification will be a multi-year project requiring a dedicated team to complete the verifications and determine if any pipeline remediation is required. This forecast includes the costs of replacing sections of pipelines as identified through the MOP verification work. MOP verification was also included in the 2017 customer engagement survey: while 43 per cent of those surveyed recommend waiting for regulation requirements to keep costs down, 40 per cent recommend proactively implementing industry standard. Spreading the verifications over several years will keep costs down and proactively implement an industry standard, which provides additional support for this program. Starting this program as forecast will mitigate the need for higher expenditures in a shorter time frame to meet these expected future mandated requirements.**	Complete	**Fail**	See investment description, IRPAs not appliable					
STO - UG	**Div_53 - Union South Storage**	Transmission Pipe & Underground Storage	**Pass**		**735428**	MOP Verification Replacement Program 2028 - S&T Assets*	**2033**	$ 2,752,350	**General: MOP verification is the process of reviewing all existing records for a pipeline system and confirming the maximum operating pressure of existing greater than 30 per cent SMYS pipeline systems based upon these records. While this is not currently mandated by code in Canada, it is required in the U.S. and is expected to become a requirement in Canada in the future. Given the number of pipelines greater than 30 per cent SMYS, MOP Verification will be a multi-year project requiring a dedicated team to complete the verifications and determine if any pipeline remediation is required. This forecast includes the costs of replacing sections of pipelines as identified through the MOP verification work. MOP verification was also included in the 2017 customer engagement survey: while 43 per cent of those surveyed recommend waiting for regulation requirements to keep costs down, 40 per cent recommend proactively implementing industry standard. Spreading the verifications over several years will keep costs down and proactively implement an industry standard, which provides additional support for this program. Starting this program as forecast will mitigate the need for higher expenditures in a shorter time frame to meet these expected future mandated requirements.**	Complete	**Fail**	See investment description, IRPAs not appliable					
STO - UG	**Div_53 - Union South Storage**	Transmission Pipe & Underground Storage	**Pass**		**735429**	MOP Verification Replacement Program 2029 - S&T Assets*	**2034**	$ 2,732,642	**General: MOP verification is the process of reviewing all existing records for a pipeline system and confirming the maximum operating pressure of existing greater than 30 per cent SMYS pipeline systems based upon these records. While this is not currently mandated by code in Canada, it is required in the U.S. and is expected to become a requirement in Canada in the future. Given the number of pipelines greater than 30 per cent SMYS, MOP Verification will be a multi-year project requiring a dedicated team to complete the verifications and determine if any pipeline remediation is required. This forecast includes the costs of replacing sections of pipelines as identified through the MOP verification work. MOP verification was also included in the 2017 customer engagement survey: while 43 per cent of those surveyed recommend waiting for regulation requirements to keep costs down, 40 per cent recommend proactively implementing industry standard. Spreading the verifications over several years will keep costs down and proactively implement an industry standard, which provides additional support for this program. Starting this program as forecast will mitigate the need for higher expenditures in a shorter time frame to meet these expected future mandated requirements.**	Complete	**Fail**	See investment description, IRPAs not appliable					
STO - UG	**Div_53 - Union South Storage**	Transmission Pipe & Underground Storage	**Pass**		**735430**	MOP Verification Replacement Program 2030 - S&T Assets*	**2035**	$ 2,829,499	**General: MOP verification is the process of reviewing all existing records for a pipeline system and confirming the maximum operating pressure of existing greater than 30 per cent SMYS pipeline systems based upon these records. While this is not currently mandated by code in Canada, it is required in the U.S. and is expected to become a requirement in Canada in the future. Given the number of pipelines greater than 30 per cent SMYS, MOP Verification will be a multi-year project requiring a dedicated team to complete the verifications and determine if any pipeline remediation is required. This forecast includes the costs of replacing sections of pipelines as identified through the MOP verification work. MOP verification was also included in the 2017 customer engagement survey: while 43 per cent of those surveyed recommend waiting for regulation requirements to keep costs down, 40 per cent recommend proactively implementing industry standard. Spreading the verifications over several years will keep costs down and proactively implement an industry standard, which provides additional support for this program. Starting this program as forecast will mitigate the need for higher expenditures in a shorter time frame to meet these expected future mandated requirements.**	Complete	**Fail**	See investment description, IRPAs not appliable					
STO - UG	**Div_53 - Union South Storage**	Transmission Pipe & Underground Storage	**Pass**		**735431**	MOP Verification Replacement Program 2031 - S&T Assets*	**2036**	$ 2,798,557	**General: MOP verification is the process of reviewing all existing records for a pipeline system and confirming the maximum operating pressure of existing greater than 30 per cent SMYS pipeline systems based upon these records. While this is not currently mandated by code in Canada, it is required in the U.S. and is expected to become a requirement in Canada in the future. Given the number of pipelines greater than 30 per cent SMYS, MOP Verification will be a multi-year project requiring a dedicated team to complete the verifications and determine if any pipeline remediation is required. This forecast includes the costs of replacing sections of pipelines as identified through the MOP verification work. MOP verification was also included in the 2017 customer engagement survey: while 43 per cent of those surveyed recommend waiting for regulation requirements to keep costs down, 40 per cent recommend proactively implementing industry standard. Spreading the verifications over several years will keep costs down and proactively implement an industry standard, which provides additional support for this program. Starting this program as forecast will mitigate the need for higher expenditures in a shorter time frame to meet these expected future mandated requirements.**	Complete	**Fail**	See investment description, IRPAs not appliable					
STO - UG	**Div_53 - Union South Storage**	Transmission Pipe & Underground Storage	**Pass**		**735432**	MOP Verification Replacement Program 2032 - S&T Assets*	**2037**	$ 2,715,983	**General: MOP verification is the process of reviewing all existing records for a pipeline system and confirming the maximum operating pressure of existing greater than 30 per cent SMYS pipeline systems based upon these records. While this is not currently mandated by code in Canada, it is required in the U.S. and is expected to become a requirement in Canada in the future. Given the number of pipelines greater than 30 per cent SMYS, MOP Verification will be a multi-year project requiring a dedicated team to complete the verifications and determine if any pipeline remediation is required. This forecast includes the costs of replacing sections of pipelines as identified through the MOP verification work. MOP verification was also included in the 2017 customer engagement survey: while 43 per cent of those surveyed recommend waiting for regulation requirements to keep costs down, 40 per cent recommend proactively implementing industry standard. Spreading the verifications over several years will keep costs down and proactively implement an industry standard, which provides additional support for this program. Starting this program as forecast will mitigate the need for higher expenditures in a shorter time frame to meet these expected future mandated requirements.**	Complete	**Fail**	See investment description, IRPAs not appliable					
STO - UG	**Div_92 - Union North Storage**	Compression Stations	**Fail**	Dollar threshold	**49021**	IROQUOIS FALLS VIBRATION MONITOR	**2023**	$ 498,212									
STO - UG	**Div_92 - Union North Storage**	Compression Stations	**Fail**	Dollar threshold	**101371**	Hagar Solar 1 Control Panel Upgrade	**2023**	$ 404,797									
STO - UG	**Div_92 - Union North Storage**	Compression Stations	**Fail**	Dollar threshold	**101493**	Hagar Solar 2 Control Panel Upgrade	**2025**	$ 1,284,814									
STO - UG	**Div_92 - Union North Storage**	Compression Stations	**Fail**	Dollar threshold	**735296**	Hagar Blowdown and Knockout Tank	**2024**	$ 256,324									
STO - UG	**Div_92 - Union North Storage**	Compression Stations	**Fail**	Dollar threshold	**736038**	Hagar Solar Yard Cable Tray Supports		$ 186,830									
STO - UG	**Div_92 - Union North Storage**	LNG	**Fail**	Dollar threshold	**49911**	Hagar Site Drainage Improvements	**2025**	$ 534,867									
STO - UG	**Div_92 - Union North Storage**	LNG	**Fail**	Dollar threshold	**734363**	Hagar Leaking Valves - Replace (Unit 2)	**2023**	$ 48,765									
STO - UG	**Div_92 - Union North Storage**	LNG	**Fail**	Dollar threshold	**735290**	Hagar Transformer Area Wall	**2023**	$ 37,366									

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Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
STO - UG	**Div_92 - Union North Storage**	LNG	**Fail**	Dollar threshold	**735291**	Hagar Pipeduct Refurbishment	**2023**	$ 186,830									
STO - UG	**Div_92 - Union North Storage**	LNG	**Fail**	Dollar threshold	**735292**	Hagar Molecular Sieves 3 Way Valve - Replace	**2024**	$ 76,897									
STO - UG	**Div_92 - Union North Storage**	LNG	**Fail**	Dollar threshold	**735293**	Hagar MCC Building - Upgrades	**2025**	$ 193,718									
STO - UG	**Div_92 - Union North Storage**	LNG	**Fail**	Dollar threshold	**735295**	Hagar Salt Bath Heater Obsolete Controls	**2024**	$ 51,265									
STO - UG	**Div_92 - Union North Storage**	LNG	**Fail**	Dollar threshold	**736832**	Hagar KVGR MSAPR Mitigations	**2023**	$ 479,529									
STO - UG	**Div_92 - Union North Storage**	LNG	**Fail**	Dollar threshold	**736935**	Hagar Obsolete Mechanical - Replace*	**2037**	$ 830,226									
STO - UG	**Div_92 - Union North Storage**	LNG	**Fail**	Dollar threshold	**736938**	Hagar Obsolete Electrical-Replace*	**2037**	$ 830,226									
STO - UG	**Div_92 - Union North Storage**	LNG	**Fail**	Dollar threshold	**736939**	Hagar Obsolete Instrumentation-Replace*	**2037**	$ 830,226									
STO - UG	**Div_92 - Union North Storage**	LNG	**Pass**		**48709**	Hagar KVGR and Cycle Mix Cooler	**2032**	$ 25,988,700	**Issue/Concern: The Hagar Liquefied Natural Gas (LNG) Plant was installed in 1968 to provide security of supply to the Sudbury industrial and distribution markets. The KVGR Compressor is one of the two compressors used to power the refrigerant process which cools the natural gas feedstock to -160°C at which point the natural gas turns into a liquid. The KVGR Compressor is necessary to produce LNG. The consequence of compressor failure is dominated by customer impact. Risk associated with failure of the KVGR Compressor is heavily influenced by the time of year, weather severity and time to mitigate the failure. Over its 50 years of operation, the 1,500 horsepower Ingersoll Rand KVGR Compressor has amassed 140,000 operational hours. The compressor is obsolete and, although normal wear components are still available in the marketplace, core compressor replacement items such as cylinders, crankshafts, pistons, etc., required to support a critical failure are no longer manufactured by the original equipment manufacturer (OEM). In the event of a critical failure, aftermarket, custom machining services are the only option for repair. In the event custom machining services are not able to make a repair, a custom-designed aftermarket casting option or complete replacement of the compressor would be required rendering the LNG plant out of service for at least one operational season and rendering the plant unable to perform its regulated requirements.** **Assets: Compressor and Cycle Mix Cooler** **Related Programs: Not applicable.**	Complete	**Fail**	See investment description, IRPAs not appliable					
STO - UG	**Div_92 - Union North Storage**	LNG	**Pass**		**49955**	Hagar JVG Compressor Upgrade	**2032**	$ 21,914,726	**Issue/Concern: The Boil-Off Gas (BOG) compressor is one of the two compressors used to power the refrigerant process which cools the natural gas feedstock to -160°C at which point the natural gas turns into a liquid. The BOG compressor was also used to recover BOG (i.e., natural gas vapours) from the liquefied natural gas (LNG) storage tank which occurs on a continuous basis due to the ambient warming of the tank exterior. In 2012, a separate compressor was installed to manage the LNG storage tank boil-off gas.** **The BOG compressor is necessary to produce LNG. The consequence of compressor failure is dominated by customer impact. Risk associated with failure of the BOG compressor is heavily influenced by the time of year, weather severity and time to mitigate the failure. Over its 50 years of operation, the 240 horsepower Ingersoll Rand BOG compressor has amassed 325,000 operational hours. The compressor is obsolete and, although normal wear components are still available in the marketplace, core compressor replacement parts such as cylinders, crankshafts, pistons, etc., required to support a critical failure are no longer manufactured by the original equipment manufacturer(OEM). In the event of a critical failure, securing used parts (which are rare) or aftermarket custom machining services are the only options for a timely repair. This was the case in 2017 when an aftermarket service was solicited to develop a weld and machine repair of a compressor cylinder which had failed. The aftermarket service was able to design a custom repair which took three months to complete. In the event that the cylinder is not repairable, a custom-designed aftermarket casting or a complete replacement of the compressor may be options. These options would take the plant out of service for at least one operational season, rendering the plant unable to perform its regulated requirements.** **Assets: BOG compressor** **Related Programs: Not applicable**	Complete	**Fail**	See investment description, IRPAs not appliable					
STO - UG	**Div_92 - Union North Storage**	LNG	**Pass**		**502916**	Hagar LNG Tank Boil Off Gas Recovery System	**2027**	$ 13,523,813	**Issue/Concern/Opportunity: During sudden atmospheric pressure changes, boil-off gas venting from the liquified natural gas (LNG) storage tank vents occurs frequently. The current boil-off compressor is undersized for Hagar, which is one of Gas Distribution and Storage's (GDS's) largest emitter of unrecovered (or destroyed) natural gas at approximately 590,000 m3/year.** **The decision on whether the project is justified under greenhouse gas (GHG) compliance or based on the Corporate Emission Reduction Plans is currently in the works. In consideration of EGI's Corporate Emission Reduction Plans and targets, Hagar is a single-point source and can be recovered by installing a single process within the existing LNG facility.** **Assets: Hagar LNG storage tank** **Related Investments: Not applicable.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Toronto	**10 - Toronto**	Distribution Pipe	**Fail**	Dollar threshold	**1638**	Alamosa Dr & Finch Ave E	**2024**	$ 51,255									
Toronto	**10 - Toronto**	Distribution Pipe	**Fail**	Dollar threshold	**1691**	Bayview & Post Compression Couplings	**2024**	$ 79,996									
Toronto	**10 - Toronto**	Distribution Pipe	**Fail**	Dollar threshold	**1692**	Bayview & St. Leonards Compression Couplings	**2025**	$ 165,665									
Toronto	**10 - Toronto**	Distribution Pipe	**Fail**	Dollar threshold	**1693**	Bayview & Steeles CC Replacement	**2026**	$ 435,926									
Toronto	**10 - Toronto**	Distribution Pipe	**Fail**	Dollar threshold	**1702**	Bloor St. W. & The Kingsway Replacement	**2024**	$ 578,698									
Toronto	**10 - Toronto**	Distribution Pipe	**Fail**	Dollar threshold	**2334**	Meadowvale & Sheppard CC Replacement	**2027**	$ 345,368									
Toronto	**10 - Toronto**	Distribution Pipe	**Fail**	Dollar threshold	**2562**	Sheppard & Markham Compression Couplings	**2026**	$ 433,766									
Toronto	**10 - Toronto**	Distribution Pipe	**Fail**	Dollar threshold	**2563**	Sheppard Ave & Brimley Rd (Compression Couplings)	**2025**	$ 147,258									
Toronto	**10 - Toronto**	Distribution Pipe	**Fail**	Dollar threshold	**2698**	Weston Rd & Imogene Compression Couplings	**2023**	$ 177,685									
Toronto	**10 - Toronto**	Distribution Pipe	**Fail**	Dollar threshold	**4792**	Copper Service Replacement - Area 10*		$ 847,573									
Toronto	**10 - Toronto**	Distribution Pipe	**Fail**	Dollar threshold	**7604**	A10: Kipling Ave & Lake Shore Blvd W, Etobicoke, PH2 Replacement	**2024**	$ 468,859									
Toronto	**10 - Toronto**	Distribution Pipe	**Fail**	Dollar threshold	**7639**	A10: 46-68 Goodview Rd (North), North York, Noded Header Replacement	**2023**	$ 432,806									
Toronto	**10 - Toronto**	Distribution Pipe	**Fail**	Dollar threshold	**7646**	HR - 160-260 Chester Lee Blvd	**2025**	$ 1,329,752									
Toronto	**10 - Toronto**	Distribution Pipe	**Fail**	Dollar threshold	**7647**	HR - 1021 Midland Ave	**2024**	$ 330,720									
Toronto	**10 - Toronto**	Distribution Pipe	**Fail**	Dollar threshold	**7649**	HR - 201 Bridletowne Circle	**2024**	$ 140,307									
Toronto	**10 - Toronto**	Distribution Pipe	**Fail**	Dollar threshold	**7651**	121 – 151 L'Amoreaux Dr Steel Header Replacements	**2025**	$ 587,884									
Toronto	**10 - Toronto**	Distribution Pipe	**Fail**	Dollar threshold	**100505**	HR - 200-250 Bridletowne Circle	**2024**	$ 474,022									
Toronto	**10 - Toronto**	Distribution Pipe	**Fail**	Dollar threshold	**100506**	HR - 1040 Bridletowne Circle	**2024**	$ 438,501									
Toronto	**10 - Toronto**	Distribution Pipe	**Fail**	Dollar threshold	**100512**	Invergordon Ave, Toronto 3" PE Replacement	**2023**	$ 447,114									

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Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
Toronto	**10 - Toronto**	Distribution Pipe	**Fail**	Dollar threshold	**102203**	NPS 12 Victoria Square Pipeline - Integrity Retrofit > 30% SMYS		$ 257,725									
Toronto	**10 - Toronto**	Distribution Pipe	**Fail**	Dollar threshold	**102419**	Relocation Program - Area 10*	**2020**	$ 13,287,715									
Toronto	**10 - Toronto**	Distribution Pipe	**Fail**	Dollar threshold	**502932**	TOR10YR - Toro to Cataford Replacement Standardization - Network # 161_169_172	**2031**	$ 1,733,079									
Toronto	**10 - Toronto**	Distribution Pipe	**Fail**	Dollar threshold	**502933**	TOR10YR - Dubray to Cornelius Replacement Standardization - Network # 161_169_172	**2030**	$ 861,827									
Toronto	**10 - Toronto**	Distribution Pipe	**Fail**	Dollar threshold	**503156**	TOR10YR - Horner and Carson Replacement - Network # 123_368_373	**2027**	$ 1,418,768									
Toronto	**10 - Toronto**	Distribution Pipe	**Fail**	Dollar threshold	**503159**	TOR10YR - Rimilton Replacement - Network # 123_368_373	**2029**	$ 1,222,291									
Toronto	**10 - Toronto**	Distribution Pipe	**Fail**	Dollar threshold	**503160**	TOR10YR - Delta and Gamma Replacement - Network # 123_368_373	**2028**	$ 1,584,146									
Toronto	**10 - Toronto**	Distribution Pipe	**Fail**	Dollar threshold	**503164**	TOR10YR - Alderbrae Replacement - Network # 123_368_373	**2028**	$ 753,747									
Toronto	**10 - Toronto**	Distribution Pipe	**Fail**	Dollar threshold	**503169**	TOR10YR - Delta North Replacement - Network # 123_368_373	**2030**	$ 1,033,185									
Toronto	**10 - Toronto**	Distribution Pipe	**Fail**	Dollar threshold	**733664**	TOR10YR - Silvercrest to Aldercrest Replacement- Network # 123_368_373	**2031**	$ 809,195									
Toronto	**10 - Toronto**	Distribution Pipe	**Fail**	Dollar threshold	**733665**	TOR10YR - Evans Industrial Replacement- Network # 123_368_373	**2032**	$ 1,111,220									
Toronto	**10 - Toronto**	Distribution Pipe	**Fail**	Dollar threshold	**733667**	TOR10YR - Browns Evans Gair Replacement- Network # 123_368_373	**2029**	$ 1,618,971									
Toronto	**10 - Toronto**	Distribution Pipe	**Fail**	Dollar threshold	**733672**	TOR10YR - Horner and Orianna Replacement- Network # 123_368_373	**2030**	$ 1,328,808									
Toronto	**10 - Toronto**	Distribution Pipe	**Fail**	Dollar threshold	**733677**	TOR10YR - Browns and Owen Replacement- Network # 123_368_373	**2031**	$ 1,313,524									
Toronto	**10 - Toronto**	Distribution Pipe	**Fail**	Dollar threshold	**733799**	TOR10YR - Belleglade and Palms Replacement Standardization - Network # 152_154	**2029**	$ 1,046,066									
Toronto	**10 - Toronto**	Distribution Pipe	**Fail**	Dollar threshold	**733801**	TOR10YR - Bradstock to Verobeach Replacement Standardization - Network # 152_154	**2031**	$ 430,538									
Toronto	**10 - Toronto**	Distribution Pipe	**Fail**	Dollar threshold	**733802**	TOR10YR - Lilac and Griffith Replacement Standardization - Network # 152_154	**2028**	$ 1,651,311									
Toronto	**10 - Toronto**	Distribution Pipe	**Fail**	Dollar threshold	**733803**	TOR10YR - Westin and Jasmine Replacement Standardization - Network # 152_154	**2029**	$ 1,372,480									
Toronto	**10 - Toronto**	Distribution Pipe	**Fail**	Dollar threshold	**735491**	TOR10YR - Treverton & Stratton Replacement - Network # 455	**2030**	$ 1,816,430									
Toronto	**10 - Toronto**	Distribution Pipe	**Fail**	Dollar threshold	**735492**	TOR10YR - Mooregate and Treverton Replacement - Network # 455	**2028**	$ 1,393,156									
Toronto	**10 - Toronto**	Distribution Pipe	**Fail**	Dollar threshold	**735495**	TOR10YR - Moorecroft and Sedgewick Replacement - Network # 455	**2030**	$ 1,807,058									
Toronto	**10 - Toronto**	Distribution Pipe	**Fail**	Dollar threshold	**735498**	TOR10YR - Bertrand and Birchmount Replacement - Network # 455	**2028**	$ 1,542,245									
Toronto	**10 - Toronto**	Distribution Pipe	**Fail**	Dollar threshold	**735817**	TOR10YR - Bay Mills and Birchmount Replacement - Network # 455	**2029**	$ 581,222									
Toronto	**10 - Toronto**	Distribution Pipe	**Fail**	Dollar threshold	**735848**	TOR10YR - Laurentide and Silverdale Replacement - Network # 455	**2031**	$ 1,676,585									
Toronto	**10 - Toronto**	Distribution Pipe	**Fail**	Dollar threshold	**735851**	TOR10YR - Groveland and Lacewood Replacement - Network # 455	**2031**	$ 1,759,440									
Toronto	**10 - Toronto**	Distribution Pipe	**Fail**	Dollar threshold	**735853**	TOR10YR - Fenelon and Graydon Hall Replacement - Network # 455	**2030**	$ 1,663,440									
Toronto	**10 - Toronto**	Distribution Pipe	**Fail**	Dollar threshold	**735864**	TOR10YR - Tiffany and Woodthorpe Replacement - Network # 455	**2032**	$ 1,122,977									
Toronto	**10 - Toronto**	Distribution Pipe	**Fail**	Dollar threshold	**735865**	TOR10YR - Anewen and Kenewen Replacement - Network # 455	**2032**	$ 1,550,831									
Toronto	**10 - Toronto**	Distribution Pipe	**Fail**	Emergent Safety	**4660**	Replacement Blanket - Area 10*		$ 21,849,759									
Toronto	**10 - Toronto**	Distribution Pipe	**Pass**		**3430**	Anode Blanket - Area 10*	**2020**	$ 7,495,416	**General: The anodes program within the corrosion program includes the required expenditure to install anodes in order to reduce the amount of down plant within EGI's 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.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Toronto	**10 - Toronto**	Distribution Pipe	**Pass**		**4160**	Vintage Steel: NPS 12 SC HP on Parliament St, Carlton St to Front St	**2023**	$ 6,830,552	**Issue/Concern:** **General Concerns: Vintage steel mains have shown signs of declining health due to the cumulative effect of poorly 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 quantitative risk assessment and the 40-year risk projection are showing an increase in the safety risk associated with steel main failures. In addition to its age, vintage steel mains are also susceptible to accelerated degradation and/or higher risk of third-party damage in the following ways:** **1)Compression couplings (e.g., mechanical fittings which are not welded onto the main) on steel mains that are not properly restrained or unrestrained could cause a loss of containment due to exposed points of thrust. In this case, the weight of the soil is required to hold the fittings in place. When the soil is disturbed, the pipe pulls out of the fitting, resulting in blowing gas through the open pipe end with the potential of full bore release of gas.** **2)Compression couplings on steel mains that are unknowingly isolated from the corrosion protection system could result in inadequate cathodic protection, leading to the assets' accelerated corrosion and potentially loss of containment.** **3)The existence of shallow blow-off valve assemblies could be damaged during excavation activities.** **4)Reduction in the original depth of cover due to urban development could increase the potential of damages due to excavation activities and increased external loading. According to the codes and standards, a minimum depth of cover is needed to ensure the appropriate distribution of weight of transportation vehicles across pipelines is not exceeded. If the depth of cover is not appropriate, excessive stresses are introduced into the pipe and failures could result.** **5)The continuous exposure of road salt and seasonal ground movement on bridge-crossing assets could result in accelerated corrosion and external loading/stresses.** **6)Lack of cathodic protection with pipe casings 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.** **7)Manufacturing defects associated with seam welds and fittings that are weak points in the distribution system could result in a loss of containment due to prolonged exposure to stress and corrosion.** **8)Latent damages to pipe coatings that were never reported to EGI for repair and became active corrosion sites could hamper the effect of the corrosion protection system and result in accelerated corrosion and potentially loss of containment.**	Planned							
Toronto	**10 - Toronto**	Distribution Pipe	**Pass**		**4760**	AMP Fitting Replacement - Area 10*	**2020**	$ 113,626,049	**AMP Fittings are a below grade transition fittings. The inserted portion of copper tubing can fail due to internal corrosion. In these cases leaks develop immediately downstream of the AMP Fitting.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Toronto	**10 - Toronto**	Distribution Pipe	**Pass**		**10088**	NPS 20 Lake Shore Replacement (Cherry to Bathurst)	**2022**	$ 3,241,970	**The NPS 20 assessment identifies risk results that exceeds EGI's risk threshold and supports the recommendation that this section of the pipeline (Cherry to Bathurst) requires replacement. The vintage steel replacement of the NPS 20 main on Lakeshore KOL from Cherry St to Bathurst will help address known pipe integrity and operational field concerns by proactively replacing the steel main approaching intolerable risk due to failing pipes or pipes in poor condition. This project will replace approximately 4.5 km of NPS 20 HP steel main and will abandon approximately 4.5 km of the existing NPS 20 HP main on Lakeshore Blvd in Toronto.**	Planned							

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Toronto	**10 - Toronto**	Distribution Pipe	**Pass**		**11443**	NPS 12 Martin Grove Rd Main Replacement: Lavington to St. Albans Rd.	**2026**	$ 23,963,834	**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 potential 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 high-pressure (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 cm, with 77 survey locations measuring less than 60 cm 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**	Planned							
Toronto	**10 - Toronto**	Distribution Pipe	**Pass**		**13612**	Service Relay Blanket - Area 10*	**2020**	$ 114,559,613	**General: 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.**	Planned							
Toronto	**10 - Toronto**	Distribution Pipe	**Pass**		**23147**	Toronto Island NPS 2 Feed Relocation	**2025**	$ 3,900,832	**Issue/Concern: Currently, a 2-inch SC HP gas line (asset 61054) is sole feed to Toronto Island and is running through Western Gap Utility Tunnel. The utility tunnel is now considered a mine shaft, preventing necessary inspections of the line and the hangers that are supporting the line. This 2-inch SC HP main was installed in 1963 and the last known inspection of this line and hangers was in 1992. Should the line fail, the only recourse would be shutting the feed to Toronto Island, losing approximately 300 customers and undertaking an emergency replacement to resume service.** **Assets: NPS 2 SC HP Main (asset ID 61054)** **Related Program: Steel Mains Replacement Program**	Planned							
Toronto	**10 - Toronto**	Distribution Pipe	**Pass**		**100339**	A10: Wilson Avenue, Toronto, VSM Replacement	**2025**	$ 91,158,784	**Issue/Concern/Opportunity:** **Phased replacement of 12 gas main from Bathurst Ave. to Walsh Ave. Main is currently protected by Rectifier.** **-The main on Wilson Ave. has numerous Pumpkins that have been installed on it. Starting from Wendell Ave. and going east towards Bathurst St.** **-Corrosion on main has been an issue on Wilson Ave. due to stray current from Toronto Transit Commission (TTC) which continues to be an ongoing concern.** **-The service connections have field-applied coatings which leaves a concern for future corrosion issues on this main.** **-Regarding the main in the middle of the road on Wilson Ave., Curbside Valve Tee (CVT) repairs are problematic due to the location of the main.** **Assets:** **There is 8.5 km of NPS 12 HP Vintage Steel Main (VSM) installed between 1955 and 1964 on Wilson Ave. between Walsh Ave. and Bathurst St., Toronto.** **Related Program: Not applicable.** **Phased replacement of 12 Gas Main from Bathurst Ave. to Walsh Ave. Main is currently protected by Rectifier.** **-The main on Wilson Ave. has numerous Pumpkins that have been installed on it. Starting from Wendell Ave. and going east towards Bathurst St.** **-Corrosion on main has been an issue on Wilson Ave. due to stray current from Toronto Transit Commission (TTC) which continues to be an ongoing concern.** **-The service connections have field-applied coatings which leaves a concern for future corrosion issues on this main.** **-Regarding the main in the middle of the road on Wilson Ave. , Curbside Valve Tee (CVT) repairs are problematic due to the location of the main.** **Assets:** **There is 8.5 km of NPS 12 HP Vintage Steel Main (VSM) installed between 1955 and 1964 on Wilson Ave. between Walsh Ave. and Bathurst St., Toronto.**	Planned							
Toronto	**10 - Toronto**	Distribution Pipe	**Pass**		**100497**	VSM - Firestone Road - 2" ST - PH1	**2023**	$ 1,968,821	**Issue/Concern/Opportunity:** **General Concerns: Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Assets: Approximately 1623.3 m 2-inch SC Intermediate Pressure (IP) to be replaced by 2-inch PE IP.** **Related Investments: Investment code #735792.**	Planned							
Toronto	**10 - Toronto**	Distribution Pipe	**Pass**		**102204**	NPS 42 GTA Transmission - Integrity Retrofit > 30% SMYS	**2025**	$ 2,577,255	**Funds to install launcher (station rebuild occurred in 2016; no provisions for launcher were included) on pipeline to allow for inline inspection are required. This will allow in-line inspection of the pipeline which is required as per the Pipeline Integrity Management Program.** **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 inline 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 that are identified through the inspections.**	Complete	**Fail**	See investment description, IRPAs not appliable					

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Toronto	**10 - Toronto**	Distribution Pipe	**Pass**		**502929**	TOR10YR - Keelesgate and Cuffley Replacement Standardization - Network # 161_169_172	**2030**	$ 1,969,836	**TOR10YR - Keelesgate and Cuffley Replacement Standardization - Network #161_169_172** **The 25 PSI Intermediate Pressure (IP) Pipe system is running close to capacity and not meeting growth needs. Plans to elevate pressure to 55 PSI requires reinforcing upgrades of mains and services.** **Scope: Replace gas mains with 300 m of NPS 4 PE and 1,040 m of NPS 2 PE, relay 90 services and reconnect 28 services.** **Resources: NPL to execute.** **Solution Impact: General Main (GM) upgrades will elevate pressure to reinforce system to meet growth requirements.** **Project Timing: To be determined.**	Planned							
Toronto	**10 - Toronto**	Distribution Pipe	**Pass**		**502935**	TOR10YR - Bayford to Dubray Replacement Standardization - Network # 161_169_172	**2030**	$ 1,872,755	**TOR10YR - Bayford to Dubray Replacement Standardization - Network #161_169_172** **The 25 PSI Intermediate Pressure (IP) Pipe system is running close to capacity and not meeting growth needs. Plans to elevate pressure to 55 PSI requires main extension to 55 PSI network and upgrades to services.** **Scope: Upgrade gas mains and add main extension with 320 m of NPS 4 PE and 1,010 m of NPS 2 PE, relay 72 services, reconnect 27 services, and remove district station.** **Resources: NPL to execute.** **Solution Impact: General Main (GM) replacement and extension will elevate pressure and reinforce system to meet growth requirements.** **Project Timing: To be determined.**	Planned							
Toronto	**10 - Toronto**	Distribution Pipe	**Pass**		**503158**	TOR10YR - Horner from Browns Line Replacement - Network # 123_368_373	**2027**	$ 1,848,507	**TOR10YR - Horner from Browns Line Replacement - Network #123_368_373** **Medium Pressure (MP) system is running close to capacity and not meeting growth needs. Plans to elevate pressure to 55 PSI system requires replacement of MP mains and services.** **Scope: Replace and upgrade gas mains and services with 575 m NPS 8 PE, 13 service relays and 8 service reconnects.** **Resources: NPL to execute.** **Solution Impact: General Main (GM) replacements are to meet pressure elevation requirements in system to meet growth requirements.** **Project Timing: To be determined.**	Planned							
Toronto	**10 - Toronto**	Distribution Pipe	**Pass**		**503161**	TOR10YR - Beta and Aldercrest Replacement - Network # 123_368_373	**2029**	$ 1,903,273	**TOR10YR - Beta and Aldercrest Replacement - Network #123_368_373** **Medium Pressure (MP) system is running close to capacity and not meeting growth needs. Plans to elevate pressure to 55 PSI system requires replacement of MP mains and services.** **Scope: Replace and upgrade gas mains and services with 575 m NPS 4 PE, 430 NPS 2 PE, 81 service relays and 44 service reconnects.** **Resources: NPL to execute.** **Solution Impact: General Main (GM) replacements are to meet pressure elevation requirements in system to meet growth requirements.** **Project Timing: To be determined.**	Planned							
Toronto	**10 - Toronto**	Distribution Pipe	**Pass**		**503165**	TOR10YR - Hallmark to Lunness Replacement - Network # 123_368_373	**2028**	$ 1,806,166	**TOR10YR - Hallmark to Lunness Replacement - Network # 123_368_373** **MP system running close to capacity and not meeting growth needs. Plans to elevate pressure to 55 PSI system requires replacement of MP mains and services** **Scope: Replace and Upgrade gas mains and services with 1100 NPS 2 PE** **88 Service Relays, 33 Service Reconnects.** **Resources: NPL to execute** **Solution Impact: GM replacements to meet pressure elevation requirements in system to meet growth requirements** **Project Timing: TBD.**	Planned							
Toronto	**10 - Toronto**	Distribution Pipe	**Pass**		**503167**	TOR10YR - Lanor and Valermo Replacement - Network # 123_368_373	**2029**	$ 1,956,524	**TOR10YR - Lanor and Valermo Replacement - Network #123_368_373** **Medium Pressure (MP) system is running close to capacity and not meeting growth needs. Plans to elevate pressure to 55 PSI system requires replacement of MP mains and services.** **Scope: Replace and upgrade gas mains and services with 1,300 NPS 2 PE, 79 service relays and 42 service reconnects.** **Resources: NPL to execute.** **Solution Impact: General Main (GM) replacements are to meet pressure elevation requirements in system to meet growth requirements.** **Project Timing: To be determined.**	Planned							
Toronto	**10 - Toronto**	Distribution Pipe	**Pass**		**503168**	TOR10YR - Beta and Gamma North Replacement - Network # 123_368_373	**2029**	$ 1,849,686	**TOR10YR - Beta and Gamma North Replacement - Network #123_368_373** **Medium Pressure (MP) system is running close to capacity and not meeting growth needs. Plans to elevate pressure to 55 PSI system requires replacement of MP mains and services.** **Scope: Replace and upgrade gas mains and services with 1,000 NPS 2 PE, 105 service relays and 27 service reconnects.** **Resources: NPL to execute.** **Solution Impact: General Main (GM) replacements are to meet pressure elevation requirements in system to meet growth requirements.** **Project Timing: To be determined.**	Planned							

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Toronto	**10 - Toronto**	Distribution Pipe	**Pass**		**733447**	TOR10YR - Aldercrest to Lunness North Replacement - Network # 123_368_373	**2029**	$ 2,156,416	**TOR10YR - Aldercrest to Lunness North Replacement - Network #123_368_373** **Medium Pressure (MP) system is running close to capacity and not meeting growth needs. Plans to elevate pressure to 55 PSI system requires replacement of MP mains and services.** **Scope: Replace and upgrade gas mains and services with 540 NPS 4 PE, 950 NPS 2 PE, 91 service relays and 52 service reconnects.** **Resources: NPL to execute.** **Solution Impact: General Main (GM) replacements are to meet pressure elevation requirements in system to meet growth requirements.** **Project Timing: To be determined.**	Planned							
Toronto	**10 - Toronto**	Distribution Pipe	**Pass**		**733448**	TOR10YR - Evans Ave Replacement- Network # 123_368_373	**2029**	$ 2,719,150	**TOR10YR - Evans Ave. Replacement - Network # 123_368_373** **Medium Pressure (MP) system is running close to capacity and not meeting growth needs. Plans to elevate pressure to 55 PSI system requires replacement of MP mains and services.** **Scope: Replace and upgrade gas mains (like for like) and services with 1,200m NPS 8 PE, 400 m NPS 4 PE, 70 service relays, 26 service reconnects, and upgrade station to 55 PSI.** **Resources: NPL to execute.** **Solution Impact: General Main (GM) replacements are to meet pressure elevation requirements in system to meet growth requirements.** **Project Timing: To be determined.**	Planned							
Toronto	**10 - Toronto**	Distribution Pipe	**Pass**		**733666**	TOR10YR - Bellman to N Carson Replacement- Network # 123_368_373	**2029**	$ 2,309,839	**TOR10YR - Bellman to N. Carson Replacement - Network #123_368_373** **Medium Pressure (MP) system is running close to capacity and not meeting growth needs. Plans to elevate pressure to 55 PSI system requires replacement of MP mains and services.** **Scope: Replace and upgrade gas mains and services with 1,400 NPS 2 PE, 119 service relays and 42 service reconnects.** **Resources: NPL to execute.** **Solution Impact: General Main (GM) replacements are to meet pressure elevation requirements in system to meet growth requirements.** **Project Timing: To be determined.**	Planned							
Toronto	**10 - Toronto**	Distribution Pipe	**Pass**		**733668**	TOR10YR - Savona and Bisset Replacement- Network # 123_368_373	**2031**	$ 2,229,896	**TOR10YR - Savona and Bisset Replacement - Network #123_368_373** **Medium Pressure (MP) system is running close to capacity and not meeting growth needs. Plans to elevate pressure to 55 PSI system requires replacement of MP mains and services.** **Scope: Replace and upgrade gas mains and services with 1,600 NPS 2 PE, 112 service relays, and 50 service reconnects.** **Resources: NPL to execute.** **Solution Impact: General Main (GM) replacements are to meet pressure elevation requirements in system to meet growth requirements.** **Project Timing: To be determined.**	Planned							
Toronto	**10 - Toronto**	Distribution Pipe	**Pass**		**733669**	TOR10YR - Delma and Ecker Replacement- Network # 123_368_373	**2031**	$ 2,367,588	**TOR10YR - Delma and Ecker Replacement - Network #123_368_373** **Medium Pressure (MP) system is running close to capacity and not meeting growth needs. Plans to elevate pressure to 55 PSI system requires replacement of MP mains and services.** **Scope: Replace and upgrade gas mains and services with 320 NPS 4 PE, 1,170 NPS 2 PE, 100 service relays and 32 service reconnects.** **Resources: NPL to execute.** **Solution Impact: General Main (GM) replacements are to meet pressure elevation requirements in system to meet growth requirements.** **Project Timing: To be determined.**	Planned							
Toronto	**10 - Toronto**	Distribution Pipe	**Pass**		**733670**	TOR10YR - Westhead Replacement- Network # 123_368_373	**2029**	$ 1,955,611	**Victoria St - Eastern - Area 60 - 1138** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: There is potential for road restrictions due to congested area.** **TOR10YR - Westhead Replacement - Network #123_368_373** **Medium Pressure (MP) system is running close to capacity and not meeting growth needs. Plans to elevate pressure to 55 PSI system requires replacement of MP mains and services.** **Scope: Replace and upgrade gas mains and services with 1,250 m NPS 2 PE, 91 service relays and 34 service reconnects.** **Resources: NPL to execute.** **Solution Impact: General Main (GM) replacements are to meet pressure elevation requirements in system to meet growth requirements.** **Project Timing: To be determined.**	Planned							

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Toronto	**10 - Toronto**	Distribution Pipe	**Pass**		**733671**	TOR10YR - Browns and Finsbury Replacement-Network # 123_368_373	**2030**	$ 2,229,129	**TOR10YR - Browns and Finsbury Replacement - Network #123_368_373** **Medium Pressure (MP) system is running close to capacity and not meeting growth needs. Plans to elevate pressure to 55 PSI system requires replacement of MP mains and services.** **Scope: Replace and upgrade gas mains and services with 180 m NPS 8 PE, 650 m NPS 4 PE, and 580 NPS 2 PE; 66 service relays and 14 service reconnects.** **Resources: NPL to execute.** **Solution Impact: General Main (GM) replacements are to meet pressure elevation requirements in system to meet growth requirements.** **Project Timing: To be determined.**	Planned							
Toronto	**10 - Toronto**	Distribution Pipe	**Pass**		**733673**	TOR10YR - Mitcham and Fulham Replacement - Network # 123_368_373	**2030**	$ 2,311,878	**TOR10YR - Mitcham and Fulham Replacement - Network #123_368_373** **Medium Pressure (MP) system is running close to capacity and not meeting growth needs. Plans to elevate pressure to 55 PSI system requires replacement of MP mains and services.** **Scope: Replace and upgrade gas mains and services with 1,400 NPS 2 PE, 85 service relays and 70 service reconnects.** **Resources: NPL to execute.** **Solution Impact: General Main (GM) replacements are to meet pressure elevation requirements in system to meet growth requirements.** **Project Timing: To be determined.**	Planned							
Toronto	**10 - Toronto**	Distribution Pipe	**Pass**		**733674**	TOR10YR - Eltham and Delma Replacement-Network # 123_368_373	**2030**	$ 2,337,978	**TOR10YR - Eltham and Delma Replacement - Network #123_368_373** **Medium Pressure (MP) system is running close to capacity and not meeting growth needs. Plans to elevate pressure to 55 PSI system requires replacement of MP mains and services.** **Scope: Replace and upgrade gas mains and services with 1,550 NPS 2 PE, 76 service relays and 58 service reconnects.** **Resources: NPL to execute.** **Solution Impact: General Main (GM) replacements are to meet pressure elevation requirements in system to meet growth requirements.** **Project Timing: To be determined.**	Planned							
Toronto	**10 - Toronto**	Distribution Pipe	**Pass**		**733675**	TOR10YR - Browns Line at Horner Replacement-Network # 123_368_373	**2030**	$ 1,867,745	**TOR10YR - Browns Line at Horner Replacement - Network #123_368_373** **Medium Pressure (MP) system is running close to capacity and not meeting growth needs. Plans to elevate pressure to 55 PSI system requires replacement of MP mains and services.** **Scope: Replace and upgrade gas mains and services with 400 NPS 8 PE, 14 service relays and 9 service reconnects. There is approximately 400 m of NPS 4 PE required on 3 services and there is 1 garage header reconnect.** **Resources: NPL to execute.** **Solution Impact: General Main (GM) replacements are to meet pressure elevation requirements in system to meet growth requirements.** **Project Timing: To be determined.**	Planned							
Toronto	**10 - Toronto**	Distribution Pipe	**Pass**		**733678**	TOR10YR - Sunset and Burlington Replacement-Network # 123_368_373	**2030**	$ 2,165,109	**TOR10YR - Sunset and Burlington Replacement- Network #123_368_373** **Medium Pressure (MP) system is running close to capacity and not meeting growth needs. Plans to elevate pressure to 55 PSI system requires replacement of MP mains and services.** **Scope: Replace and upgrade gas mains and services with 920 NPS 2 PE and 400 NPS 4 PE, 73 service relays and 44 service reconnects.** **Resources: NPL to execute.** **Solution Impact: General Main (GM) replacements are to meet pressure elevation requirements in system to meet growth requirements.** **Project Timing: To be determined.**	Planned							
Toronto	**10 - Toronto**	Distribution Pipe	**Pass**		**733679**	TOR10YR - Albright and Roseland Replacement-Network # 123_368_373	**2030**	$ 2,417,166	**TOR10YR - Albright and Roseland Replacement - Network #123_368_373** **Medium Pressure (MP) system is running close to capacity and not meeting growth needs. Plans to elevate pressure to 55 PSI system requires replacement of MP mains and services.** **Scope: Replace and upgrade gas mains and services with 900 NPS 2 PE, 500 NPS 4 PE, 81 service relays and 98 service reconnects.** **Resources: NPL to execute.** **Solution Impact: General Main (GM) replacements are to meet pressure elevation requirements in system to meet growth requirements.** **Project Timing: To be determined.**	Planned							

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Toronto	**10 - Toronto**	Distribution Pipe	**Pass**		**733680**	TOR10YR - Foch and Woodbury Replacement- Network # 123_368_373	**2031**	$ 2,349,456	**TOR10YR - Foch and Woodbury Replacement - Network #123_368_373** **Medium Pressure (MP) system is running close to capacity and not meeting growth needs. Plans to elevate pressure to 55 PSI system requires replacement of MP mains and services.** **Scope: Replace and upgrade gas mains and services with 1,220 NPS 2 PE, 220 NPS 4 PE, 98 service relays and 51 service reconnects.** **Resources: NPL to execute.** **Solution Impact: General Main (GM) replacements to meet pressure elevation requirements in system to meet growth requirements.** **Project Timing: To be determined.**	Planned							
Toronto	**10 - Toronto**	Distribution Pipe	**Pass**		**733681**	TOR10YR - St Lucie Replacement Standardization - Network # 152_154	**2027**	$ 2,174,985	**TOR10YR - St. Lucie Replacement Standardization - Network #152_154** **The 25 PSI Intermediate Pressure (IP) Pipe system is running close to capacity and not meeting growth needs. Plans to elevate pressure to 55 PSI requires reinforcing upgrades of mains and services.** **Scope: Replace gas mains with 500 m of NPS 4 PE and 760 m of NPS 2 PE, relay 120 services and reconnect 58 services.** **Resources: NPL to execute.** **Solution Impact: General Main (GM) replacement will elevate pressure to reinforce system to meet growth requirements.** **Project Timing: To be determined.**	Planned							
Toronto	**10 - Toronto**	Distribution Pipe	**Pass**		**733682**	TOR10YR - Gulfstream and Franson Replacement Standardization - Network # 152_154	**2028**	$ 1,923,418	**TOR10YR - Gulfstream and Franson Replacement Standardization - Network # 152_154** **25 PSI IP Pipe system running close to capacity and not meeting growth needs. Plans to elevate pressure to 55 PSI requires reinforcing upgrades of mains and services** **Scope: Replace gas mains with 400m of NPS 4 PE and 630m of NPS 2 PE** **Relay 95 services; Reconnect 37 Services** **Resources: NPL to execute** **Solution Impact: GM Replacement in order to elevate pressure to reinforce system to meet growth requirements** **Project Timing: TBD**	Planned							
Toronto	**10 - Toronto**	Distribution Pipe	**Pass**		**733683**	TOR10YR - Verobeach Replacement Standardization - Network # 152_154	**2031**	$ 2,526,511	**TOR10YR - Verobeach Replacement Standardization - Network #152_154** **The 25 PSI Intermediate Pressure (IP) Pipe system is running close to capacity and not meeting growth needs. Plans to elevate pressure to 55 PSI requires reinforcing upgrades of mains and services.** **Scope: Replace gas mains with 690 m of NPS 4 PE and 900 m of NPS 2 PE, relay 135 services, and reconnect 48 services.** **Resources: NPL to execute.** **Solution Impact: General Main (GM) replacement will elevate pressure to reinforce system to meet growth requirements.** **Project Timing: To be determined.**	Planned							
Toronto	**10 - Toronto**	Distribution Pipe	**Pass**		**733800**	TOR10YR - Coral Gable Replacement Standardization - Network # 152_154	**2031**	$ 2,322,509	**TOR10YR - Coral Gable Replacement Standardization - Network #152_154** **The 25 PSI Intermediate Pressure (IP) Pipe system is running close to capacity and not meeting growth needs. Plans to elevate pressure to 55 PSI requires reinforcing upgrades of mains and services.** **Scope: Replace gas mains with 570 m of NPS 4 PE, 1,170 m of NPS 2 PE (like for like), relay 79 services, reconnect 52 services and remove 25 PSI station.** **Resources: NPL to execute.** **Solution Impact: General Main (GM) replacement will elevate pressure to reinforce system to meet growth requirements.** **Project Timing: To be determined.**	Planned							
Toronto	**10 - Toronto**	Distribution Pipe	**Pass**		**733804**	TOR10YR - Yorkdale and Wallasey Replacement Standardization - Network # 152_154	**2030**	$ 2,327,023	**TOR10YR - Yorkdale and Wallasey Replacement Standardization - Network #152_154** **The 25 PSI Intermediate Pressure (IP) Pipe system is running close to capacity and not meeting growth needs. Plans to elevate pressure to 55 PSI requires reinforcing upgrades of mains and services.** **Scope: Replace gas mains with 1,160 m of NPS 2 PE, relay 129 services and reconnect 60 services.** **Resources: NPL to execute.** **Solution Impact: General Main (GM) replacement will elevate pressure to reinforce system to meet growth requirements.** **Project Timing: To be determined.**	Planned							
Toronto	**10 - Toronto**	Distribution Pipe	**Pass**		**733805**	TOR10YR - Starview and Weston Replacement Standardization - Network # 152_154	**2030**	$ 2,371,979	**TOR10YR - Starview and Weston Replacement Standardization - Network #152_154** **25 PSI Intermediate Pressure (IP) Pipe system is running close to capacity and not meeting growth needs. Plans to elevate pressure to 55 PSI requires reinforcing upgrades of mains and services.** **Scope: Replace gas mains with 1,330 m of NPS 2 PE, relay 146 services and reconnect 12 services.** **Resources: NPL to execute.** **Solution Impact: General Main (GM) replacement will elevate pressure to reinforce system to meet growth requirements.** **Project Timing: To be determined.**	Planned							

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Toronto	**10 - Toronto**	Distribution Pipe	**Pass**		**733806**	TOR10YR - Gaydon and Highbury Replacement Standardization - Network # 152_154	**2029**	$ 2,308,231	**TOR10YR - Gaydon and Highbury Replacement Standardization - Network #152_154** **25 PSI Intermediate Pressure (IP) Pipe system is running close to capacity and not meeting growth needs. Plans to elevate pressure to 55 PSI requires reinforcing upgrades of mains and services.** **Scope: Install 350 m of NPS 4 PE and replace gas mains with 1,330 m of NPS 2 PE, relay 117 services, reconnect 55 services and upgrade station to 55 PSI.** **Resources: NPL to execute.** **Solution Impact: General Main (GM) replacement will elevate pressure to reinforce system to meet growth requirements.** **Project Timing: To be determined.**	Planned							
Toronto	**10 - Toronto**	Distribution Pipe	**Pass**		**733910**	TOR10YR - Browns Line and Jellicoe Replacement- Network # 123_368_373	**2032**	$ 5,197,777	**TOR10YR - Browns Line and Jellicoe Replacement- Network #123_368_373** **Medium Pressure (MP) system is running close to capacity and not meeting growth needs. Plans to elevate pressure to 55 PSI system requires replacement of MP mains and services.** **Scope: Replace and upgrade gas mains (like for like) and services with 80 m NPS 8 PE, 950 m NPS 4 PE, 2,275 m NPS 2 PE, 196 service relays, and 145 service reconnects; abandon station and outlet piping.** **Resources: NPL to execute.** **Solution Impact: General Main (GM) replacements are to meet pressure elevation requirements in system to meet growth requirements.** **Project Timing: To be determined.**	Planned							
Toronto	**10 - Toronto**	Distribution Pipe	**Pass**		**734406**	Vintage Steel Replacement Program - 10 Toronto*	**2026**	$ 25,545,052	**Issue/Concern: The VS Steel Main Replacement Program is both a reactive and proactive asset renewal program. Over the next ten years, the program will focus on reactively replacing steel mains that have experienced failure and integrity issues. The planned replacement will replace gas mains that exhibit signs of approaching end-of-life found in recent leak survey results and through field discovery of integrity issues (such as poor coating condition, severe corrosion, insufficient depth of cover or exposure, and leaks), as supported by the DIMP risk model.**	Planned							
Toronto	**10 - Toronto**	Distribution Pipe	**Pass**		**735485**	TOR10YR - Foxbridge-Roebuck Replacement - Network # 277	**2031**	$ 2,354,728	**TOR10YR - Foxbridge-Roebuck Replacement - Network #277** **Intermediate Pressure (IP) system is running close to capacity and not meeting growth needs. Plans to elevate pressure to 55 PSI system from 25 PSI requires replacement of some mains and services.** **Scope: Replace and upgrade gas mains with 450 m NPS 2 PE, 192 service relays, and 12 service reconnects.** **Resources: NPL to execute.** **Solution Impact: Gas plant replacements are to meet pressure elevation requirements in system to meet growth requirements.** **Project Timing: To be determined.**	Planned							
Toronto	**10 - Toronto**	Distribution Pipe	**Pass**		**735487**	TOR10YR - Birchmount & Foxbridge Replacement - Network # 277	**2028**	$ 2,752,982	**TOR10YR - Birchmount & Foxbridge Replacement - Network # 277** **IP system running close to capacity and not meeting growth needs. Plans to elevate pressure to 55 PSI system from 25 PSI requires replacement of some mains and services** **Scope: Install Replace and Upgrade gas mains with 1500m NPS 2 PE, 1000m NPS 4 PE** **32 Service Relays, CC removals** **Resources: NPL to execute** **Solution Impact: Gas Plant replacements and install to meet pressure elevation requirements in system to meet growth requirements** **Project Timing: TBD**	Planned							
Toronto	**10 - Toronto**	Distribution Pipe	**Pass**		**735489**	TOR10YR - Willowmount & Birchmount Replacement - Network # 277	**2031**	$ 2,353,768	**TOR10YR - Willowmount and Birchmount Replacement - Network #277** **Intermediate Pressure (IP) system is running close to capacity and not meeting growth needs. Plans to elevate pressure to 55 PSI system from 25 PSI requires replacement of some mains and services.** **Scope: There are 181 service relays, 73 service reconnects, station removal/abandonment, and compression couplings (CCs) removal.** **Resources: NPL to execute.** **Solution Impact: Gas plant replacements are to meet pressure elevation requirements in system to meet growth requirements.** **Project Timing: To be determined.**	Planned							
Toronto	**10 - Toronto**	Distribution Pipe	**Pass**		**735497**	TOR10YR - Kingsdown and Ranstone Replacement - Network # 455	**2028**	$ 2,736,597	**TOR10YR - Kingsdown and Ranstone Replacement - Network # 455** **IP system running close to capacity and not meeting growth needs. Plans to elevate pressure to 55 PSI system from 25 PSI requires replacement of some mains and services** **Scope: Replace and Upgrade gas mains with 1100m NPS 2 PE, 100m NPS 4 (Like for Like)** **120 Service Relays, 91 Service Reconnects** **Resources: NPL to execute** **Solution Impact: Gas Plant replacements to meet pressure elevation requirements in system to meet growth requirements** **Project Timing: TBD**	Planned							
Toronto	**10 - Toronto**	Distribution Pipe	**Pass**		**735501**	TOR10YR - Ionview South Replacement - Network # 455	**2028**	$ 2,230,996	**TOR10YR - Ionview South Replacement - Network # 455** **IP system running close to capacity and not meeting growth needs. Plans to elevate pressure to 55 PSI system from 25 PSI requires replacement of some mains and services** **Scope:Replace and Upgrade gas mains with 1300m NPS 2 PE (Like for Like)** **Install tie-in 30m NPS 4** **109 Service Relays, 32 Service Reconnects** **Remove Station, tie-in to network 262** **Resources: NPL to execute** **Solution Impact: Gas Plant replacements to meet pressure elevation requirements in system to meet growth requirements** **Project Timing: TBD**	Planned							

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Toronto	10 - Toronto	Distribution Pipe	Pass		735819	TOR10YR - Bay Mills and Birchmount Services Replacement - Network # 455	2029	$ 2,616,745	**TOR10YR - Bay Mills and Birchmount Services Replacement - Network #455** **Intermediate pressure (IP) system is running close to capacity and not meeting growth needs. Plans to elevate pressure to 55 PSI system from 25 PSI requires upgrades and replacement of some mains and services.** **Scope: Replace and upgrade gas services including 274 service relays and compression coupling (CC) removals.** **Resources: NPL to execute.** **Solution Impact: Gas plant replacements to meet pressure elevation requirements in system to meet growth requirements.** **Project Timing: To be determined.** **Permit: Some services may encroach in regulated area.**	Planned							
Toronto	10 - Toronto	Distribution Pipe	Pass		735820	TOR10YR - Amethyst and Cass Replacement - Network # 455	2029	$ 4,372,195	**TOR10YR - Amethyst and Cass Replacement - Network #455** **Intermediate Pressure (IP) system is running close to capacity and not meeting growth needs. Plans to elevate pressure to 55 PSI system from 25 PSI requires upgrades and replacement of some mains and services** **Scope: Replace and upgrade gas mains and services with 2,350 m NPS 2 PE, 1,000 m NPS 4 PE (like for like), 98 service relays, 27 service reconnects, and compression coupling (CC) removals.** **Resources: NPL to execute.** **Solution Impact: Gas plant replacements are to meet pressure elevation requirements in system to meet growth requirements.** **Project Timing: To be determined.**	Planned							
Toronto	10 - Toronto	Distribution Pipe	Pass		735821	TOR10YR - Aragon and Malamute Replacement - Network # 455	2030	$ 2,458,254	**TOR10YR - Aragon and Malamute Replacement - Network #455** **Intermediate Pressure (IP) system is running close to capacity and not meeting growth needs. Plans to elevate pressure to 55 PSI system from 25 PSI requires upgrades and replacement of some mains and services.** **Scope: Replace and upgrade gas mains and services with 1,600 m NPS 2 PE, 121 service relays and 17 service reconnects.** **Resources: NPL to execute.** **Solution Impact: Gas plant replacements are to meet pressure elevation requirements in system to meet growth requirements.** **Project Timing: To be determined.**	Planned							
Toronto	10 - Toronto	Distribution Pipe	Pass		735822	TOR10YR - Scarden and Tourmaline Replacement - Network # 455	2030	$ 2,545,630	**TOR10YR - Scarden and Tourmaline Replacement - Network #455** **Intermediate Pressure (IP) system is running close to capacity and not meeting growth needs. Plans to elevate pressure to 55 PSI system from 25 PSI requires upgrades and replacement of some mains and services.** **Scope: Replace and upgrade gas mains and services with 1,600 m NPS 2 PE, 250 m NPS 4, 96 service relays, and 18 service reconnects.** **Resources: NPL to execute.** **Solution Impact: Gas plant replacements are to meet pressure elevation requirements in system to meet growth requirements.** **Project Timing: To be determined.**	Planned							
Toronto	10 - Toronto	Distribution Pipe	Pass		735824	TOR10YR - Moraine Hill and Sunmount Replacement - Network # 455	2031	$ 3,799,870	**TOR10YR - Moraine Hill and Sunmount Replacement - Network #455** **Intermediate Pressure (IP) system is running close to capacity and not meeting growth needs. Plans to elevate pressure to 55 PSI system from 25 PSI requires upgrades and replacement of some mains and services.** **Scope: Replace and upgrade gas mains and services with 2,800 m NPS 2 PE, 450 m NPS 4 (like for like), 154 service relays and 34 service reconnects.** **Resources: NPL to execute.** **Solution Impact: Gas plant replacements are to meet pressure elevation requirements in system to meet growth requirements.** **Project Timing: To be determined.**	Planned							
Toronto	10 - Toronto	Distribution Pipe	Pass		735830	TOR10YR - Birchmount South Sheppard Replacement - Network # 455	2029	$ 3,731,512	**TOR10YR - Birchmount South Sheppard Replacement - Network #455** **Intermediate Pressure (IP) system is running close to capacity and not meeting growth needs. Plans to elevate pressure to 55 PSI system from 25 PSI requires upgrades and replacement of some mains and services.** **Scope: Replace and upgrade gas mains and services with 900 m NPS 8 PE (like for like), 17 service relays, 3 service reconnects, 100 m NPS 1.25 header, and compression coupling (CC) removals.** **Resources: NPL to execute.** **Solution Impact: Gas plant replacements are to meet pressure elevation requirements in system to meet growth requirements.** **Project Timing: To be determined.**	Planned							

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Toronto	10 - Toronto	Distribution Pipe	Pass		735835	TOR10YR - Allanford and Pender Replacement - Network # 455	2031	$ 3,673,333	TOR10YR - Allanford and Pender Replacement - Network #455 Intermediate Pressure (IP) system is running close to capacity and not meeting growth needs. Plans to elevate pressure to 55 PSI system from 25 PSI requires upgrades and replacement of some mains and services. Scope: Replace and upgrade gas mains and services with 500 m NPS 6 PE, 600 m NPS 4 PE, 1,700 m NPS 2 PE (like for like), 140 service relays and 20 service reconnects. Resources: NPL to execute. Solution Impact: Gas plant replacements are to meet pressure elevation requirements in system to meet growth requirements. Project Timing: To be determined.	Planned							
Toronto	10 - Toronto	Distribution Pipe	Pass		735836	TOR10YR - Araman and Earlton Replacement - Network # 455	2031	$ 3,673,333	TOR10YR - Araman and Earlton Replacement - Network #455 Intermediate Pressure (IP) system is running close to capacity and not meeting growth needs. Plans to elevate pressure to 55 PSI system from 25 PSI requires upgrades and replacement of some mains and services. Scope: Replace and upgrade gas mains and services with 2,800 m NPS 6 PE (like for like), 176 service relays, and 19 service reconnects. Resources: NPL to execute. Solution Impact: Gas plant replacements are to meet pressure elevation requirements in system to meet growth requirements. Project Timing: To be determined.	Planned							
Toronto	10 - Toronto	Distribution Pipe	Pass		735839	TOR10YR - Colingwood and Dempster Replacement - Network # 455	2030	$ 2,494,336	TOR10YR - Colingwood and Dempster Replacement - Network #455 Intermediate Pressure (IP) is system running close to capacity and not meeting growth needs. Plans to elevate pressure to 55 PSI system from 25 PSI requires upgrades and replacement of some mains and services. Scope: Replace and upgrade gas mains and services with 50 m NPS 4 PE, 650 NPS 8 PE, 137 service relays and 29 service reconnects. Resources: NPL to execute. Solution Impact: Gas plant replacements are to meet pressure elevation requirements in system to meet growth requirements. Project Timing: To be determined.	Planned							
Toronto	10 - Toronto	Distribution Pipe	Pass		735847	TOR10YR - Birchmount North Ellesmere Replacement - Network # 455	2030	$ 2,314,209	TOR10YR - Birchmount North Ellesmere Replacement - Network #455 Intermediate Pressure (IP) system running close to capacity and not meeting growth needs. Plans to elevate pressure to 55 PSI system from 25 PSI requires upgrades and replacement of some mains and services. Scope: Replace and upgrade gas mains and services with 650 m NPS 8 PE, 50 NPS 2 PE (like for like) 36 service relays, 7 service reconnects (commercial services), and compression coupling (CC) removals. Resources: NPL to execute. Solution Impact: Gas plant replacements are to meet pressure elevation requirements in system to meet growth requirements. Project Timing: To be determined. Toronto and Region Conservation Authority (TRCA) Permit - Some services and mains may encroach into regulated area.	Planned							
Toronto	10 - Toronto	Distribution Pipe	Pass		735849	TOR10YR - Larabee and Tetbury Replacement - Network # 455	2031	$ 2,010,061	TOR10YR - Larabee and Tetbury Replacement - Network #455 Intermediate Pressure (IP) is system running close to capacity and not meeting growth needs. Plans to elevate pressure to 55 PSI system from 25 PSI requires upgrades and replacement of some mains and services. Scope: Replace and upgrade gas mains and services with 1,700m NPS 2 PE (like for like) 72 service relays and 45 service reconnects. Resources: NPL to execute. Solution Impact: Gas plant replacements are to meet pressure elevation requirements in system to meet growth requirements. Project Timing: To be determined. Permit: Some services and mains may encroach into regulated area.	Planned							
Toronto	10 - Toronto	Distribution Pipe	Pass		735850	TOR10YR - Three Valley Dr Replacement - Network # 455	2031	$ 2,879,976	TOR10YR - Three Valley Dr. Replacement - Network #455 Intermediate Pressure (IP) system is running close to capacity and not meeting growth needs. Plans to elevate pressure to 55 PSI system from 25 PSI requires upgrades and replacement of some mains and services. Scope: Replace and upgrade gas mains and services with 60 m NPS 6 PE, 900 m NPS 4 PE, 500 m NPS 2 PE (like for like), 148 service relays, and 39 service reconnects. Resources: NPL to execute. Solution Impact: Gas Plant replacements are to meet pressure elevation requirements in system to meet growth requirements. Project Timing: To be determined. Permit: Some services and mains may encroach into regulated area.	Planned							

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Toronto	**10 - Toronto**	Distribution Pipe	**Pass**		**735852**	TOR10YR - Valentine and York Mills Replacement - Network # 455	**2030**	$ 2,252,485	**TOR10YR - Valentine and York Mills Replacement - Network #455** **Intermediate Pressure (IP) system is running close to capacity and not meeting growth needs. Plans to elevate pressure to 55 PSI system from 25 PSI requires upgrades and replacement of some mains and services.** **Scope: Replace and upgrade gas mains and services with 200 m NPS 4 PE, 650 m NPS 2 PE, 168 service relays, 20 service reconnects, and compression coupling (CC) removals.** **Resources: NPL to execute.** **Solution Impact: Gas plant replacements are to meet pressure elevation requirements in system to meet growth requirements.** **Permit: Some services and mains may encroach into regulated area.**	Planned							
Toronto	**10 - Toronto**	Distribution Pipe	**Pass**		**735854**	TOR10YR - Fenside and Lynedock Replacement - Network # 455	**2030**	$ 5,285,359	**TOR10YR - Fenside and Lynedock Replacement - Network #455** **Intermediate Pressure (IP) system is running close to capacity and not meeting growth needs. Plans to elevate pressure to 55 PSI system from 25 PSI requires upgrades and replacement of some mains and services.** **Scope: Replace and upgrade gas mains and services with 150 m NPS 6 PE, 400 m NPS 4 PE, 2,700 m NPS 2 PE (like for like), 301 service relays, 46 service reconnects, and compression coupling (CC) removals.** **Resources: NPL to execute.** **Solution Impact: Gas plant replacements are to meet pressure elevation requirements in system to meet growth requirements.** **Permit – Creek Crossing**	Planned							
Toronto	**10 - Toronto**	Distribution Pipe	**Pass**		**735855**	TOR10YR - Roywood and York Mills Replacement - Network # 455	**2032**	$ 5,008,877	**TOR10YR - Roywood and York Mills Replacement - Network #455** **Intermediate Pressure (IP) system is running close to capacity and not meeting growth needs. Plans to elevate pressure to 55 PSI system from 25 PSI requires upgrades and replacement of some mains and services.** **Scope: Replace and upgrade gas mains and services with 200 m NPS 2 PE (like for like), 569 service relays, 1 service reconnect, and compression coupling (CC) removals.** **Resources: NPL to execute.** **Solution Impact: Gas plant replacements are to meet pressure elevation requirements in system to meet growth requirements.** **Permit: Some services and mains may encroach into regulated area.**	Planned							
Toronto	**10 - Toronto**	Distribution Pipe	**Pass**		**735856**	TOR10YR - Sloane and Ruscica Replacement - Network # 455	**2032**	$ 2,972,934	**TOR10YR - Sloane and Ruscica Replacement - Network #455** **Intermediate Pressure (IP) system is running close to capacity and not meeting growth needs. Plans to elevate pressure to 55 PSI system from 25 PSI requires upgrades and replacement of some mains and services.** **Scope: Replace and upgrade gas mains and services with 30 m NPS 6 PE, 1,100 m NPS 4 PE, 1,000 m NPS 2 PE (like for like), 71 service relays, 34 service reconnects, and compression coupling (CC) removals.** **Resources: NPL to execute.** **Solution Impact: Gas plant replacements are to meet pressure elevation requirements in system to meet growth requirements.** **Permit: Some services and mains may encroach into regulated area.**	Planned							
Toronto	**10 - Toronto**	Distribution Pipe	**Pass**		**735857**	TOR10YR - Wigmore and Draycott Replacement - Network # 455	**2031**	$ 2,969,602	**TOR10YR - Wigmore and Draycott Replacement - Network #455** **Intermediate Pressure (IP) system is running close to capacity and not meeting growth needs. Plans to elevate pressure to 55 PSI system from 25 PSI requires upgrades and replacement of some mains and services.** **Scope: Replace and upgrade gas mains and services with 1,900 m NPS 2 PE, 104 service relays, and 54 service reconnects.** **Resources: NPL to execute.** **Solution Impact: Gas plant replacements are to meet pressure elevation requirements in system to meet growth requirements.** **Permit: Some services and mains may encroach into regulated area.**	Planned							
Toronto	**10 - Toronto**	Distribution Pipe	**Pass**		**735858**	TOR10YR - Elvaston Replacement - Network # 455	**2031**	$ 2,516,300	**TOR10YR - Elvaston Replacement - Network #455** **Intermediate Pressure (IP) system is running close to capacity and not meeting growth needs. Plans to elevate pressure to 55 PSI system from 25 PSI requires upgrades and replacement of some mains and services.** **Scope: Replace and upgrade gas mains and services with 1,600 m NPS 2 PE, 102 service relays and 30 service reconnects.** **Resources: NPL to execute.** **Solution Impact: Gas plant replacements are to meet pressure elevation requirements in system to meet growth requirements.** **Toronto and Region Conservation Authority (TRCA) Permit - Some services and mains may encroach into regulated area.**	Planned							

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Toronto	**10 - Toronto**	Distribution Pipe	**Pass**		**735859**	TOR10YR - Eccleston and Tinder Replacement - Network # 455	**2031**	$ 2,144,073	**TOR10YR - Eccleston and Tinder Replacement - Network #455** **Intermediate Pressure (IP) system is running close to capacity and not meeting growth needs. Plans to elevate pressure to 55 PSI system from 25 PSI requires upgrades and replacement of some mains and services.** **Scope: Replace and upgrade gas mains and services with 1,200 m NPS 2 PE, 104 service relays, 24 service reconnects, and compression coupling (CC) removals.** **Resources: NPL to execute.** **Solution Impact: Gas plant replacements are to meet pressure elevation requirements in system to meet growth requirements.** **Toronto and Region Conservation Authority (TRCA) Permit: Some services and mains may encroach into regulated area.**	Planned							
Toronto	**10 - Toronto**	Distribution Pipe	**Pass**		**735860**	TOR10YR - North Sloane Replacement - Network # 455	**2031**	$ 3,558,130	**TOR10YR - North Sloane Replacement - Network #455** **Intermediate Pressure (IP) system is running close to capacity and not meeting growth needs. Plans to elevate pressure to 55 PSI system from 25 PSI requires upgrades and replacement of some mains and services.** **Scope: Replace and upgrade gas mains and services with 100 m NPS 6 PE, 900 m NPS 4 PE, 1,350 m NPS 2 PE (like for like), 62 service relays, 20 service reconnects, and compression coupling (CC) removals.** **Resources: NPL to execute.** **Solution Impact: Gas plant replacements are to meet pressure elevation requirements in system to meet growth requirements.** **Project Timing: To be determined.**	Planned							
Toronto	**10 - Toronto**	Distribution Pipe	**Pass**		**735861**	TOR10YR - Sweeney Replacement - Network # 455	**2031**	$ 5,123,664	**TOR10YR - Sweeney Replacement - Network #455** **Intermediate Pressure (IP) system is running close to capacity and not meeting growth needs. Plans to elevate pressure to 55 PSI system from 25 PSI requires upgrades and replacement of some mains and services.** **Scope: Replace and upgrade gas mains and services with 750 m NPS 6 PE, 200 m NPS 4 PE, and 2,000 m NPS 2 PE (like for like), 124 service relays, 65 service reconnects, and compression coupling (CC) removals.** **Resources: NPL to execute.** **Solution Impact: Gas plant replacements are to meet pressure elevation requirements in system to meet growth requirements.** **Project Timing: To be determined.** **Permit: Some services and mains may encroach into regulated area.**	Planned							
Toronto	**10 - Toronto**	Distribution Pipe	**Pass**		**735862**	TOR10YR - Knighton and Prestbury Replacement - Network # 455	**2031**	$ 3,509,187	**TOR10YR - Knighton and Prestbury Replacement - Network #455** **Intermediate Pressure (IP) system is running close to capacity and not meeting growth needs. Plans to elevate pressure to 55 PSI system from 25 PSI requires upgrades and replacement of some mains and services.** **Scope: Replace and upgrade gas mains and services with 200 m NPS 4 PE, 2,100 m NPS 2 PE (like for like) 89 service relays, and 82 service reconnects.** **Resources: NPL to execute.** **Solution Impact: Gas plant replacements are to meet pressure elevation requirements in system to meet growth requirements.** **Project Timing: To be determined.**	Planned							
Toronto	**10 - Toronto**	Distribution Pipe	**Pass**		**735863**	TOR10YR - Carnforth and Wyndcliff Replacement - Network # 455	**2032**	$ 4,062,625	**TOR10YR - Carnforth and Wyndcliff Replacement - Network #455** **Intermediate Pressure (IP) system is running close to capacity and not meeting growth needs. Plans to elevate pressure to 55 PSI system from 25 PSI requires upgrades and replacement of some mains and services.** **Scope: Replace and upgrade gas mains and services with 700 m NPS 4 PE, 2,200 m NPS 2 PE (like for like), 100 service relays, 104 service reconnects, and compression coupling (CC) removals.** **Resources: NPL to execute.** **Solution Impact: Gas plant replacements are to meet pressure elevation requirements in system to meet growth requirements.** **Project Timing: To be determined.**	Planned							
Toronto	**10 - Toronto**	Distribution Pipe	**Pass**		**735866**	TOR10YR - Pharmacy and Dewey Replacement - Network # 455	**2032**	$ 1,808,003	**TOR10YR - Pharmacy and Dewey Replacement - Network #455** **Intermediate Pressure (IP) system is running close to capacity and not meeting growth needs. Plans to elevate pressure to 55 PSI system from 25 PSI requires upgrades and replacement of some mains and services.** **Scope: Replace and upgrade gas mains and services with 350 m NPS 2, 219 service relays, 7 service reconnects, and compression coupling (CC) removals.** **Resources: NPL to execute.** **Solution Impact: Gas plant replacements are to meet pressure elevation requirements in system to meet growth requirements.** **Project Timing: To be determined.**	Planned							

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Toronto	**10 - Toronto**	Distribution Pipe	**Pass**		**735867**	TOR10YR - Victoria Park Ivordale Replacement - Network # 455	**2032**	$ 2,556,852	**TOR10YR - Victoria Park Ivordale Replacement - Network #455** **Intermediate Pressure (IP) system is running close to capacity and not meeting growth needs. Plans to elevate pressure to 55 PSI system from 25 PSI requires upgrades and replacement of some mains and services.** **Scope: Replace and upgrade gas mains and services with 760 m NPS 4 PE, 50 m NPS 2 PE (like for like), 214 service relays, 18 service reconnects, and compression coupling (CC) removals.** **Resources: NPL to execute.** **Solution Impact: Gas plant replacements are to meet pressure elevation requirements in system to meet growth requirements.** **Project Timing: To be determined.**	Planned							
Toronto	**10 - Toronto**	Distribution Pipe	**Pass**		**735868**	TOR10YR - Combermere Replacement - Network # 455	**2032**	$ 4,289,303	**TOR10YR - Combermere Replacement - Network #455** **Intermediate Pressure (IP) system is running close to capacity and not meeting growth needs. Plans to elevate pressure to 55 PSI system from 25 PSI requires upgrades and replacement of some mains and services.** **Scope: Replace and upgrade gas mains and services with 550 m NPS 4 PE, 2,700 m NPS 2 PE (like for like), 181 service relays and 45 service reconnects.** **Resources: NPL to execute.** **Solution Impact: Gas plant replacements are to meet pressure elevation requirements in system to meet growth requirements.** **Project Timing: To be determined.**	Planned							
Toronto	**10 - Toronto**	Distribution Pipe	**Pass**		**735869**	TOR10YR - Parkwoods Village Replacement - Network # 455	**2032**	$ 3,359,999	**TOR10YR - Parkwoods Village Replacement - Network #455** **Intermediate Pressure (IP) system is running close to capacity and not meeting growth needs. Plans to elevate pressure to 55 PSI system from 25 PSI requires upgrades and replacement of some mains and services** **Scope: Replace and upgrade gas mains and services with 650 m NPS 4 PE, 2,200 m NPS 2 PE (like for like) 145 service relays, and 33 service reconnects.** **Resources: NPL to execute.** **Solution Impact: Gas plant replacements are to meet pressure elevation requirements in system to meet growth requirements.** **Project Timing: To be determined.**	Planned							
Toronto	**10 - Toronto**	Distribution Pipe	**Pass**		**735870**	TOR10YR - Brookbanks and Valley Woods Replacement - Network # 455	**2032**	$ 3,535,865	**TOR10YR - Brookbanks and Valley Woods Replacement - Network #455** **Intermediate Pressure (IP) system is running close to capacity and not meeting growth needs. Plans to elevate pressure to 55 PSI system from 25 PSI requires upgrades and replacement of some mains and services.** **Scope: Replace and upgrade gas mains and services with 1,000 m NPS 4 PE, 1,850 m NPS 2 PE (like for like), compression couplings (CCs), 65 service relays, and 26 service reconnects.** **Resources: NPL to execute.** **Solution Impact: Gas plant replacements are to meet pressure elevation requirements in system to meet growth requirements.** **Project Timing: To be determined.** **Permit: Some services and mains may encroach into regulated area.**	Planned							
Toronto	**10 - Toronto**	Distribution Pipe	**Pass**		**735871**	TOR10YR - Truxford and Overbank Replacement - Network # 455	**2032**	$ 2,491,913	**TOR10YR - Truxford and Overbank Replacement - Network #455** **Intermediate Pressure (IP) system is running close to capacity and not meeting growth needs. Plans to elevate pressure to 55 PSI system from 25 PSI requires upgrades and replacement of some mains and services.** **Scope: Replace and upgrade gas mains and services with 100 m NPS 4 PE, 2,100 m NPS 2 PE (like for like), compression coupling (CC) removals, 61 service relays, and 54 service reconnects.** **Resources: NPL to execute.** **Solution Impact: Gas Plant replacements are to meet pressure elevation requirements in system to meet growth requirements.** **Project Timing: To be determined.** **Permit – Some services and mains may encroach into regulated area.**	Planned							
Toronto	**10 - Toronto**	Distribution Pipe	**Pass**		**735872**	TOR10YR - Wallingford Replacement - Network # 455	**2032**	$ 3,061,749	**TOR10YR - Wallingford Replacement - Network #455** **Intermediate Pressure (IP) system is running close to capacity and not meeting growth needs. Plans to elevate pressure to 55 PSI system from 25 PSI requires upgrades and replacement of some mains and services.** **Scope: Replace and upgrade gas mains and services with 500 m NPS 4 PE, 2,100 m NPS 2 PE (like for like), compression coupling (CC) removals, 94 service relays, and 31 service reconnects.** **Resources: NPL to execute.** **Solution Impact: Gas plant replacements are to meet pressure elevation requirements in system to meet growth requirements.** **Project Timing: To be determined.** **Permit – Some services and mains may encroach into regulated area.**	Planned							

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Toronto	**10 - Toronto**	Distribution Pipe	**Pass**		**736024**	A:10 Dawlish Ave & Valleyanna Dr	**2023**	$ 1,620,985	**Issue/Concern/Opportunity: Replace approximately 850 m of pipe on Dawlish Ave. and Valleyanna Dr. due to pipe age and opportunity to remove single-sourced district station that is currently leaking.** **Assets: STN#12443A to be removed** **Related Program: Not applicable**	Planned							
Toronto	**10 - Toronto**	Distribution Stations	**Fail**	Dollar threshold	**2719**	YONGE AND STEELES FEEDER	**2024**	$ 476,378									
Toronto	**10 - Toronto**	Distribution Stations	**Fail**	Dollar threshold	**7765**	DOWNSVIEW FEEDER	**2026**	$ 500,584									
Toronto	**10 - Toronto**	Distribution Stations	**Fail**	Dollar threshold	**7773**	NEILSON RD FEEDER	**2025**	$ 864,675									
Toronto	**10 - Toronto**	Distribution Stations	**Fail**	Dollar threshold	**7775**	SIGNET & FINCH FEEDER	**2025**	$ 617,729									
Toronto	**10 - Toronto**	Distribution Stations	**Fail**	Dollar threshold	**18811**	SHEPPARD & KENNEDY DISTRICT	**2023**	$ 244,769									
Toronto	**10 - Toronto**	Distribution Stations	**Fail**	Dollar threshold	**18812**	BAYVIEW & SHEPPARD DISTRICT	**2023**	$ 264,032									
Toronto	**10 - Toronto**	Distribution Stations	**Fail**	Dollar threshold	**18815**	BAYVIEW & BYNG DISTRICT	**2023**	$ 576,073									
Toronto	**10 - Toronto**	Distribution Stations	**Fail**	Dollar threshold	**18816**	BRIMLEY & ELESMERE DISTRICT	**2024**	$ 425,564									
Toronto	**10 - Toronto**	Distribution Stations	**Fail**	Dollar threshold	**18818**	BAY & SCOLLARD DISTRICT LP	**2025**	$ 1,026,877									
Toronto	**10 - Toronto**	Distribution Stations	**Fail**	Dollar threshold	**18844**	SHEPPARD AVE E & GRAND MARSHALL DISTRICT	**2024**	$ 160,128									
Toronto	**10 - Toronto**	Distribution Stations	**Fail**	Dollar threshold	**18845**	REPLIN & LAWRENCE DISTRICT	**2026**	$ 202,611									
Toronto	**10 - Toronto**	Distribution Stations	**Fail**	Dollar threshold	**18886**	SPADINA & MACPHERSON DISTRICT	**2023**	$ 1,246,911									
Toronto	**10 - Toronto**	Distribution Stations	**Fail**	Dollar threshold	**18887**	DELORAINE & YONGE DISTRICT	**2025**	$ 284,905									
Toronto	**10 - Toronto**	Distribution Stations	**Fail**	Dollar threshold	**18888**	HARVIE & MORRISON DISTRICT	**2025**	$ 854,792									
Toronto	**10 - Toronto**	Distribution Stations	**Fail**	Dollar threshold	**18889**	KIPLING & NORTH QUEEN DISTRICT	**2023**	$ 411,481									
Toronto	**10 - Toronto**	Distribution Stations	**Fail**	Dollar threshold	**18963**	YORKGATE & FINCH DISTRICT	**2027**	$ 509,229									
Toronto	**10 - Toronto**	Distribution Stations	**Fail**	Dollar threshold	**18964**	CALEDONIA & RAITHERM DISTRICT	**2024**	$ 499,565									
Toronto	**10 - Toronto**	Distribution Stations	**Fail**	Dollar threshold	**18965**	MCCOWAN AND SHEPPARD DISTRICT	**2027**	$ 746,302									
Toronto	**10 - Toronto**	Distribution Stations	**Fail**	Dollar threshold	**20376**	FINCH & HALESIA DISTRICT	**2026**	$ 333,479									
Toronto	**10 - Toronto**	Distribution Stations	**Fail**	Dollar threshold	**21023**	Telemetry Internal Work Scheduling	**2025**	$ 955									
Toronto	**10 - Toronto**	Distribution Stations	**Fail**	Dollar threshold	**101006**	14378A - TRETHEWAY & CLEARVIEW DISTRICT	**2023**	$ 263,971									
Toronto	**10 - Toronto**	Distribution Stations	**Fail**	Dollar threshold	**101229**	Enbridge Yard CNG Station B		$ 368,462									
Toronto	**10 - Toronto**	Distribution Stations	**Fail**	Dollar threshold	**501540**	Station B - Electrical	**2025**	$ 129,173									
Toronto	**10 - Toronto**	Distribution Stations	**Fail**	Dollar threshold	**733451**	Station B Actuated Valve and Upgrades	**2029**	$ 136,972									
Toronto	**10 - Toronto**	Distribution Stations	**Fail**	Dollar threshold	**733503**	NPS 30 Eglington Valve Actuation	**2024**	$ 128,138									
Toronto	**10 - Toronto**	Distribution Stations	**Fail**	Dollar threshold	**733504**	NPS 30/NPS 36 Sheppard Interconnect Valve Actuation	**2025**	$ 129,173									
Toronto	**10 - Toronto**	Distribution Stations	**Fail**	Dollar threshold	**734640**	CNG - Kennedy Upgrade/Redesign		$ 342,901									
Toronto	**10 - Toronto**	Distribution Stations	**Fail**	Dollar threshold	**735176**	17904A Rathburn and Dorlen District	**2023**	$ 518,341									
Toronto	**10 - Toronto**	Distribution Stations	**Fail**	Dollar threshold	**735177**	14435A BIRMINGHAM & NINTH DISTRICT	**2023**	$ 283,174									
Toronto	**10 - Toronto**	Distribution Stations	**Fail**	Dollar threshold	**735179**	12696A BROOKFIELD AND DONINO DISTRICT	**2023**	$ 244,769									
Toronto	**10 - Toronto**	Distribution Stations	**Fail**	Dollar threshold	**735181**	3226575 SHEPPARD & MORNINGSIDE DISTRICT	**2023**	$ 219,830									
Toronto	**10 - Toronto**	Distribution Stations	**Fail**	Dollar threshold	**735182**	2936953 MEADOWVALE & GENERATION DISTRICT	**2024**	$ 232,141									
Toronto	**10 - Toronto**	Distribution Stations	**Fail**	Dollar threshold	**735183**	2936745 MARKHAM & VERNE DISTRICT	**2024**	$ 130,528									
Toronto	**10 - Toronto**	Distribution Stations	**Fail**	Dollar threshold	**735187**	14887A GLAMORGAN & KENNEDY DISTRICT	**2024**	$ 287,369									
Toronto	**10 - Toronto**	Distribution Stations	**Fail**	Dollar threshold	**735188**	17461A CAVERLY & MARTINGROVE DISTRICT	**2025**	$ 180,404									
Toronto	**10 - Toronto**	Distribution Stations	**Fail**	Emergent Safety	**10295**	Station Emergency Replacement Blanket - All Areas*		$ 2,684,940									
Toronto	**10 - Toronto**	Distribution Stations	**Pass**		**1147**	KEELE AND FINCH FEEDER	**2025**	$ 5,256,580	**Issue/Concern: The Keele and Finch Feeder station is adjacent to a transit station (subway) and there are electric transmission towers nearby. Due to transit upgrades, this project was deferred for many years. The subsystem issues are described below.** **Pipe, Valves & Others: Updated Mechanical Piping is required for this station. The isolation valves for the pressure control are hard to turn. The pressure control stations inlet/outlet valves are seized.** **Heating System: The Heating system is aging and an update is required at this station.** **Pressure Control: This station has four boot-style regulators that are undersized and require replacement.** **Odourant System: Not required.** **Telemetry/Electrical: Telemetry assets have been deemed within the hazardous classified area. Relocation of assets is required. New Control Wave Micro unit and associated connections are required. New generator is required to support backup power requirements. New Annubar on outlet of station is required for redundant measurement.** **Measurement: Not required.** **Building: One building needs to be considered to house all assets due to the surrounding environment (i.e., subway station, etc.) if additional land cannot be obtained.** **Assets: Station# 16997A** **Related Programs: Not applicable.**	Planned							
Toronto	**10 - Toronto**	Distribution Stations	**Pass**		**3605**	BAYVIEW FEEDER	**2024**	$ 6,532,378	**Pipe, Valves & Others: Updated piping is required for this station to connect the new valve's and fittings and other associated materials. New inlet (NPS 12) and outlet (NPS 16) piping configurations are required to separate Maximum Operating Pressures (MOPs). Bayview Station will need to be shut in to execute piping installation. Station inlet filtration (gas separator) will be considered during the rebuild.** **Heating System: Updated heating is required at this station. Due to the area, this would more than likely be a conventional boiler system with two boilers minimum for heating load and redundancy. New building (concrete is required) with Glycol piping and new Glycol substance is required. The building is to be outfitted with all electrical elements (-5°C outlet temps during winter). A new heat exchanger will be required.** **Pressure Control: New regulation is required to support pressure cuts to separate MOPs. Three new runs (Operator and Monitor) will be required. These will be Becker Control Regulators and six are required.** **Odourant System: Not required.** **Telemetry/Electrical: Telemetry assets have been deemed within the hazardous classified area. Relocation of assets is required. New Control Wave Micro unit and associated connections are required. A new generator is required to support backup power requirements. Pressure and temperature transmitters (two each) are required.** **Measurement: The orifice plate is improperly sized and not accessible (below grade) and is to be replaced with above grade including piping. New Annubar on outlet of station is required for redundant measurement.** **Building: A new, large building format is required. The boiler, regulator and Remoter Terminal Unit (RTU) are all to be under one building (similar to Station A approach).** **Compliance/Civil: Site grading and new security fencing (galvanized) including new swing gate and crash bar access will be required. Existing lands will need to be confirmed if property is owned or leased. Tree trimming/removal may be required. The station is**	Planned							

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Toronto	**10 - Toronto**	Distribution Stations	**Pass**		**17403**	NGT Existing customer Maintenance Capital - (+2027)*		$ 2,796,843	**Issue/concern: EGI Fleet operators can continue to achieve fuel cost savings and reduced emission benefits by investing in the wellbeing of the NGV station. This can be achieves by adopting continuously upgrading the major NGV equipment as part of the maintenance strategy. By upgrading the major NGV equipment, EGD can extend the life cycle of the equipment, resulting in a more cost effective way of operating the NGV stations. Assets: There is a number of current NGV Station EGI maintains.**	Complete	**Fail**	See investment description, IRPAs not appliable for CNG					
Toronto	**10 - Toronto**	Distribution Stations	**Pass**		**18962**	(O)-ELLESMERE / BUDEA	**2025**	$ 195,388	**Issue/Concern: BOOT ABOVE GROUND BOX AGE: 31.9 Customer Count: 554 Utilization: 0.01858793 Can't short Sense # of Regs/Avg Size: 4 / 0in Assets: Related Program (if applicable): N/A**	Complete	**Fail**	See investment description, IRPAs not appliable					
Toronto	**10 - Toronto**	Distribution Stations	**Pass**		**503183**	Albion Feeder Station Control Valve Upgrade	**2023**	$ 2,638,215	**At Albion Gate, valve F54201D controls the flow rate from the EGT line to the TC Energy Kings North outlet. All gas flowing to TC Energy must pass through the valve; there is no bypass, isolation, or redundancy included in the existing design. If this valve (F54201D) failed (and required maintenance), the inlet to both the EGI system and TC Energy's outlets would be affected. The original purpose of the valve was to control flow to TC Energy to their contractual limit when flows on the EGT line were at their peaks. This control would guarantee the inlet pressure to the station feeding the EGI XHP systems which would be sufficient during peak operations.** **It was expected that this valve would be primarily 100% open and only be in service on the coldest of high-market demand days. Utilization was expected to be less than 10% of the winter days. In the winter period November 1, 2020 to February 25, 2021, the valve had been less than 100% open, 50% of the time (1407 hours / 2788 hours – source SCADA). Gas Control has utilized this valve more often for two purposes: (1) to carry higher pressure to Albion Gate for the distribution station; and (2) to maintain the operation of Parkway West compression within tolerances.** **Parkway West compressors are each 40,000 HP plus units. For the units to operate in their limited emission mode, both the volume pumped by the compressor and the lift across the compressor must be maintained within specific ranges. Using F54201D at Albion to limit flow to TC Energy allows the EGT line to act as a buffer for the compression. Compression volumes and lift can be maintained by operating the EGT line at higher pressure on warmer days.** **Risks: With no bypass and a single valve, a failure of the valve to open when needed will not allow EGI to deliver contracted quantities to TC Energy. Although this station rarely operates in summer months, summer would be the only time to work on the valve controls.** **Recommendation: Identify the appropriate design for the control valve feeding TC Energy Kings North that will meet EGI's control, bypass, and maintenance requirements.**	Planned							
Toronto	**10 - Toronto**	Distribution Stations	**Pass**		**733809**	Parliament & Winchester Station Replacement - Execution Phase	**2023**	$ 1,147,246	**Phase 2 (Execution Phase) of the Parliament and Winchester Station Replacement** **Phase 2 project was created because original investment 1217 exceeded 5-years. The first station purchased in 2017 will not be used for this station rebuild and will be repurposed for future projects.**	Planned							
Toronto	**10 - Toronto**	Distribution Stations	**Pass**		**735180**	12377A PURPLE DUSK TRAIL & NEILSON DISTRICT	**2023**	$ 143,021	**Issue/Concern/Opportunity: (from Field) • Below ground box** **Assets: District Station 12377A**	Complete	**Fail**	See investment description, IRPAs not appliable					
Toronto	**10 - Toronto**	Growth	**Pass**		**3405**	Area 10 - Apartment Traditional - New Construction*		$ 31,629	**Apartment - An apartment customer is a multi-residential dwelling containing more than six units that is bulk-metered Issue/ Concern: EGI is mandated to provide new or upgraded natural gas services to feasible residential customers.**	Planned							
Toronto	**10 - Toronto**	Growth	**Pass**		**3720**	Area 10 - Industrial - New Construction*		$ 435,336	**Industrial New Construct. A customer intending to run an ind. mfg business in a newly-built facility and intending to use natural gas.**	Planned							
Toronto	**10 - Toronto**	Growth	**Pass**		**3402**	Area 10 - Apartment Ensuite - New Construction*		$ 33,932,813	**Issue/Concern: Vertical Subdivision refers to a multiple unit residential building where each suite is individually metered.** **Issue/Concern: EGI is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGI will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGI develops a customer additions forecast using a number of information sources: - Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities - Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates - Projections developed by external consultants specializing in population growth forecasting - Municipal long-term plans: EGI extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report. EGI reviews the following when determining feasibility: - The number of potential new customers - The consumption of natural gas by new customers - The cost of extending the gas main The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGI determines the CIAC amount and communicate with the applicant(s) in writing. Generally, there are three components of capital investments needed to support customer addition requirements: - Installation costs related to mains, services, and meters - Material costs related to mains, services and meters - Costs related to measurement and regulation equipment required to support customer growth.** **Assets: All applicable assets.** **Related Program: N/A**	Planned							
Toronto	**10 - Toronto**	Growth	**Pass**		**3406**	Area 10 - Commercial - New Construction*		$ 88,357,565	**Commercial New Construction- A commercial customer in a newly-built facility intending to use natural gas for a commercial business.** **Issue/Concern: EGI is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGI will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGI develops a customer additions forecast using a number of information sources: - Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities - Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates - Projections developed by external consultants specializing in population growth forecasting - Municipal long-term plans: EGI extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report. EGI reviews the following when determining feasibility: - The number of potential new customers - The consumption of natural gas by new customers - The cost of extending the gas main The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGI determines the CIAC amount and communicate with the applicant(s) in writing. Generally, there are three components of capital investments needed to support customer addition requirements: - Installation costs related to mains, services, and meters - Material costs related to mains, services and meters - Costs related to measurement and regulation equipment required to support customer growth.** **Assets: All applicable assets.** **Related Program: N/A**	Planned							

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Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
Toronto	**10 - Toronto**	Growth	**Pass**		**3407**	Area 10 - Commercial - Replacement*		$ 20,036,048	**Commercial Replacement - A commercial replacement customer using a fuel other than natural gas for commercial business and is converting to natural gas.** **Issue/Concern: EGI is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGI will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGI develops a customer additions forecast using a number of information sources: - Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities - Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates - Projections developed by external consultants specializing in population growth forecasting - Municipal long-term plans: EGI extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report. EGI reviews the following when determining feasibility: - The number of potential new customers - The consumption of natural gas by new customers - The cost of extending the gas main The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGI determines the CIAC amount and communicate with the applicant(s) in writing. Generally, there are three components of capital investments needed to support customer addition requirements: - Installation costs related to mains, services, and meters - Material costs related to mains, services and meters - Costs related to measurement and regulation equipment required to support customer growth.** **Assets: All applicable assets.** **Related Program: N/A**	Planned							
Toronto	**10 - Toronto**	Growth	**Pass**		**3408**	Area 10 - Residential - Replacement*		$ 98,154,218	**Issue/Concern: Residential Replacement refers to a residential replacement customer using a fuel other than natural gas for domestic purposes and is converting to natural gas.** **Issue/Concern: EGI is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGI will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGI develops a customer additions forecast using a number of information sources: - Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities - Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates - Projections developed by external consultants specializing in population growth forecasting - Municipal long-term plans: EGI extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report. EGI reviews the following when determining feasibility: - The number of potential new customers - The consumption of natural gas by new customers - The cost of extending the gas main The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGI determines the CIAC amount and communicate with the applicant(s) in writing. Generally, there are three components of capital investments needed to support customer addition requirements: - Installation costs related to mains, services, and meters - Material costs related to mains, services and meters - Costs related to measurement and regulation equipment required to support customer growth.** **Assets: All applicable assets.** **Related Program: N/A**	Planned							
Toronto	**10 - Toronto**	Growth	**Pass**		**3700**	Area 10 - Residential - New Construction*		$ 118,460,850	**Issue/Concern: Residential New Construction refers to a new residential construction development of detached single homes constructed by the builder for domestic purposes.** **Issue/Concern: EGI is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGI will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGI develops a customer additions forecast using a number of information sources: - Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities - Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates - Projections developed by external consultants specializing in population growth forecasting - Municipal long-term plans: EGI extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report. EGI reviews the following when determining feasibility: - The number of potential new customers - The consumption of natural gas by new customers - The cost of extending the gas main The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGI determines the CIAC amount and communicate with the applicant(s) in writing. Generally, there are three components of capital investments needed to support customer addition requirements: - Installation costs related to mains, services, and meters - Material costs related to mains, services and meters - Costs related to measurement and regulation equipment required to support customer growth.** **Assets: All applicable assets.** **Related Program: N/A**	Planned							

* in the Investment Name indicates a program item. Program items are unique as they represent numerous projects grouped together and budgeted in advance. This results in forecast spend appearing larger than it would at the project level and it also impacts the in-service dates

Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
Toronto	**10 - Toronto**	Growth	**Pass**		**7710**	McCowan Ave HP Reinforcement	**2022**	$ 31,173	**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: This reinforcement is meant to support upstream and downstream load growth, bring back the flexibility EGI previously had in the system and to reduce dependency of other stations feeding the Intermediate Pressure (IP) network. Both McCowan and Southdale and South Unionville districts have been set to 40 psi and 50 psi respectively in 2016 to increase the tail-end pressures in the High Pressure (HP) network. Operations has posed concerns with leaving these stations set at their current outlet pressures for an extended period of time. If the reinforcement is completed, the set pressures can be increased to 55 psi, the downstream networks' intended pressure setting. Monitor points have been set up near the tail end of the HP network to determine if a reinforcement would be required in the near future. Mostly large volume customers and HP-IP district stations are fed off of the HP network and maintaining an inlet above 100 psi has always been an EGI standard (according to the PDR). As indicated, there are many alternate sources available, but the pressure tends to diminish as it approaches the tail end of the network. This constraint will become apparent in the event of a damage or repairs need to be performed on one of the alternate feeds. If the reinforcement is performed at the date indicated, key decisions can be made in the field with high levels of confidence.** **• Pressure Issue/Concern: McCowan and Southdale District is approaching the minimum inlet pressure of 100 psi. There is a need to shift the flow to other sources in order to boost pressures near the tail end of the HP network.** **• Risk If Not Completed: If the inlet to STN 36013A - McCowan and Southdale District or STN 32758A - South Unionville and McCowan District (Markham) fall below 100 psi during design conditions in 2021, approximately 5,000 customers downstream will be lost. Scheduled maintenance for both stations beyond 2017 will need to occur in summer months due to the instability of the HP feed. If this reinforcement is completed by the in-service date, either station could be taken offline for servicing without customer losses.** **Updates from 2021 review**	Planned							
Toronto	**10 - Toronto**	Growth	**Pass**		**11850**	Area 10 - Sales Stations - Replacements*		$ 6,380,455	**Area 10 - Sales Station - Replacements**	Planned							
Toronto	**10 - Toronto**	Growth	**Pass**		**736616**	Area 10 Sales Station - New*		$ 18,731,558	**Area 10 - Sales Station - New**	Planned							
Toronto	**10 - Toronto**	Growth	**Pass**		**736690**	Station Rebuild 14164A Lakeshore & Stadium SRP	**2023**	$ 1,151,410	**Issue/Concern/Opportunity: Model shows a requirement to increase capacity through pressure control for the district station. ERX also shows outlet pressure dropping at 34 Degree Day (DD). System Reinforcement Plan (SRP) predicts the downstream will continue to grow in the next 10 years.** **Assets: District station rebuild** **Related Program: Not applicable**	Planned							
Toronto	**10 - Toronto**	Utilization	**Pass**		**13543**	MXGI Area 10*	**2019**	$ 142,732,655	**Meters: Meters are used to determine the gas consumption input of customer billing. The replacement program for meters is mandated by Measurement Canada. The program includes: testing, repair, and replacement requirements of meters and instruments. All verified meters are approved by Measurement Canada with an issuance of a certificate which identifies that the meter complies with Electricity and Gas Specification S-EG-02. The Company must ensure all measurement devices remain in compliance for annual audits by Measurement Canada. Measurement Canada specifies tolerances under which the meter must operate in the field. The Company must demonstrate that all aspects of its meter sampling, maintenance, and replacement comply with these criteria in order to be accredited by Measurement Canada to be an "Authorized Service Provider" and adhere to Measurement Canada's accreditation standard S-A-01. Meters may also require exchange for issues such as: damages, leaks, customer billing issues. Regulation: Regulators are the last line of defense for over-pressure to the customer. The condition of regulation systems is determined by regulator performance, corrosion of piping and regulators, and adherence to installation specifications. Failure of the regulation system can cause pressured gas to enter the premise, resulting in failure of gas equipment, loss of containment, and potentially fire or explosion.**	Complete	**Fail**	See investment description, IRPAs not appliable					

* in the Investment Name indicates a program item. Program items are unique as they represent numerous projects grouped together and budgeted in advance. This results in forecast spend appearing larger than it would at the project level and it also impacts the in-service dates

TRANSMISSION SYSTEM CONTINUITY
HILARY THOMPSON, DIRECTOR S&T BUSINESS DEVELOPMENT

1. This evidence provides results of the transmission system continuity. The transmission system continuity evidence details the processes to obtain the demand, capacity and shortfall of Enbridge Gas's transmission systems and the facility solution to mitigate the capacity shortfall to provide safe and reliable service to Enbridge Gas's customers on design day over the forecast period.

2. This section of evidence is linked to other sections of evidence in the area of Capital Planning, Asset Management Plan and Dawn Parkway Long-Term Utilization. The facilities required to serve the system shortfall as determined by the transmission system continuity are an input into the Asset Management Plan provided at Exhibit 2, Tab 6, Schedule 2, Section 5.3.6, pages 194-202. The Dawn Parkway System (one of Enbridge Gas's transmission systems) will be used and useful through the next IR term as detailed in the Dawn Parkway Long-Term Utilization evidence as provided at Exhibit 1, Tab 11, Schedule 1.

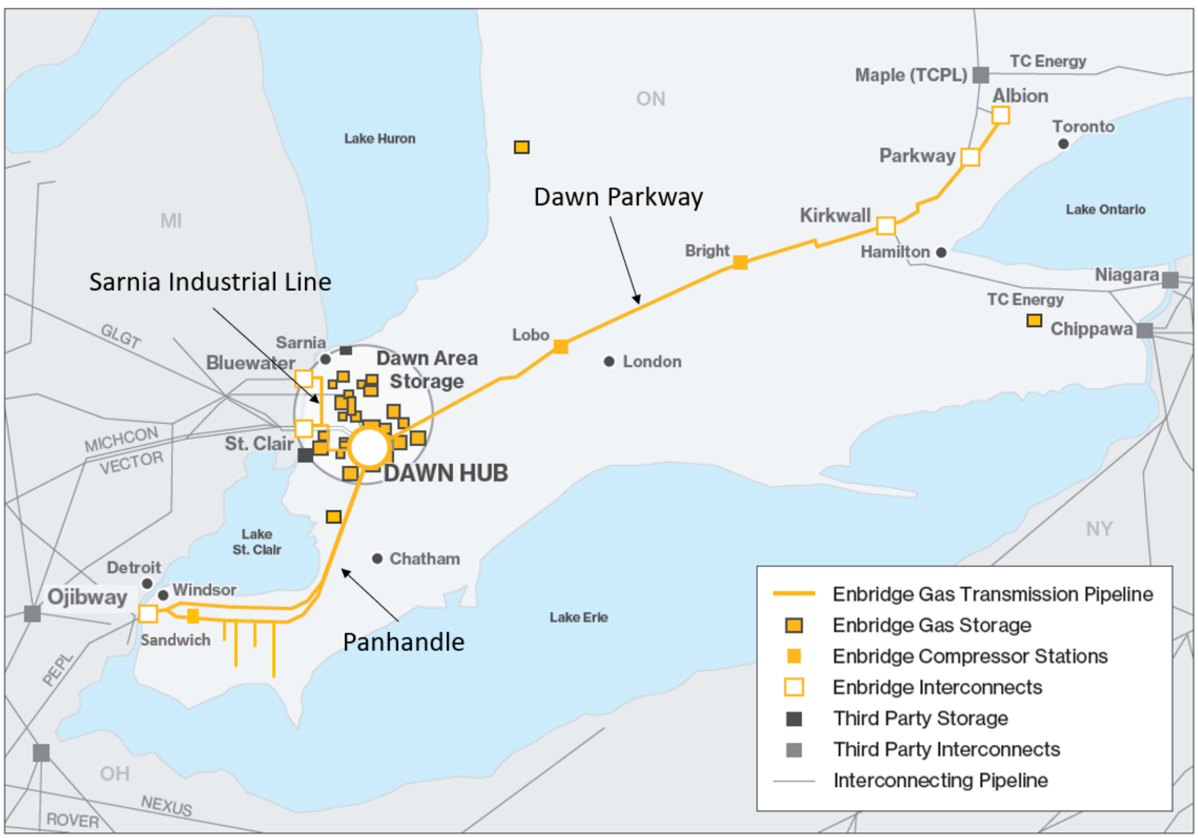
3. This evidence is organized as follows:
    1. Introduction
    2. Transmission System Overview
    3. Design Day Information
    4. System Operating Criteria
    5. System Continuity

1. Introduction

4. Enbridge Gas's transmission systems are a major conduit for gas transportation in Ontario, Eastern Canada, and the Midwest and Northeastern United States. These

transmission systems are evaluated on an annual basis to ensure the facilities are adequate from a capacity and reliability standpoint to serve the forecast design day demand of Enbridge Gas's in-franchise and ex-franchise customers. The transmission systems referred to in this evidence include the Dawn Parkway Transmission System (Dawn Parkway System), Panhandle Transmission System (Panhandle System) and Sarnia Industrial Line (SIL). A map showing the location of the transmission systems is shown in Figure 1.

Figure 1: Enbridge Gas Transmission Systems



5. Enbridge Gas has a duty to its customers to provide safe and reliable service in all weather conditions. Since natural gas demand fluctuates substantially during the

year due to weather and customer operation, pipeline systems are designed to accommodate variations in demand and in particular are sized to accommodate the potential highest demand day. This design condition is termed the design day and typically occurs during the winter when the utility experiences the coldest day observed based on previous experienced heating degree days[1]. Enbridge Gas plans to meet this need by estimating the design day demand and planning the corresponding facilities. Enbridge Gas must have a sufficient volume of gas in storage and sufficient assets to move the upstream gas supply and gas out of storage, into the transmission systems, which directly or indirectly feed the downstream distribution systems to ultimately serve customer demand on design day.

6. Design day demand is developed using the process provided at Exhibit 4, Tab 2, Schedule 3 using actual customer consumption data, weather data, customer contracts, and company forecasts. The design day demand forecast and system operating criteria is used in the hydraulic modelling network analysis to determine if there is sufficient capacity to serve the customer demand, or if there is a capacity shortfall that will need to be mitigated (i.e., identifies a need for a facility, non-facility or hybrid solution). Solutions to meet these future needs may include construction of new facilities (Facility Alternatives), contracting of commercial services (i.e. peaking services), demand-side and supply-side Integrated Resource Planning Alternatives (IRPA), Enhanced Targeted Energy Efficiency projects (Non-Facility Alternatives) or a combination of both facility and non-facility alternatives (i.e., Hybrid Alternatives).

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[1] Some systems, such as SIL, can have their highest demand or design condition occurring during the summer season.

2. Transmission System Overview

7. The transmission system is composed of facilities including pipelines, measurement and regulation stations, and compressor stations. The physical system moves gas from supply locations to delivery locations along the pipeline to meet the volumetric demand and pressure requirements of Enbridge Gas customers.

8. A summary of the major components of the Dawn Parkway System, the Panhandle System and SIL is provided in the sections that follow.

2.1. Dawn Parkway Transmission System

9. The Dawn Parkway System is comprised of a series of parallel pipelines, compressor stations, and measurement and regulating stations. The system starts at the Dawn Hub (also known as Dawn Compressor Station or Dawn) located in the Township of Dawn-Euphemia, southeast of the City of Sarnia, and extends to the Parkway East and West Compressor Stations (Parkway) located on the western border of the City of Mississauga. From Parkway, the Dawn Parkway System continues northeast to the Albion Station (Albion), located in the City of Toronto. A map showing the overview of the Dawn Parkway System is shown in Attachment 1.

10. The Dawn Parkway System operates at a 6160 kPag maximum operating pressure (MOP) and consists of the following pipelines:
    a) NPS 26 from Dawn to Parkway;
    b) NPS 34 from Dawn to Parkway;
    c) NPS 48 from Dawn to Parkway and a second NPS 48 between Hamilton Valve Site and Milton Valve Site; and

d) NPS 42 from Dawn to the Kirkwall Custody Transfer Station (Kirkwall) and the NPS 42 Albion Line[2] from Parkway to the Albion Road Station. The Albion Line operates at 6450 kPag.

11. Besides Dawn, there are three mainline compressor stations along the Dawn Parkway System: Lobo Compressor Station (Lobo) which is northwest of the City of London, Bright Compressor Station (Bright) which is located northeast of the City of Woodstock, and Parkway which is located on the western border of the City of Mississauga. The compressor stations at Dawn, Lobo, Bright and Parkway have Loss of Critical Unit (LCU) coverage.

12. Dawn is the main source of supply to the Dawn Parkway System. On design day, the flow of gas is easterly from Dawn towards Parkway. Additional supply is received at Kirkwall and Parkway which reduces the need for pipeline infrastructure and diversifies gas supply pathways. Ex-franchise customer gas flowing on paths which are opposite in direction (counter flowing) to the prevailing flow direction (i.e. Parkway to Dawn, Kirkwall to Dawn, or Parkway to Kirkwall) are not considered to be available for network analysis purposes on design day. The utilization of these paths on design day are not controlled by Enbridge Gas and there is no contractual guarantee that ex-franchise customers will flow on these paths[3].

13. The Dawn Parkway System interconnects with TC Energy's TransCanada Mainline at Parkway and the Kings North interconnect within the Albion Road Station, with

[2] Also known as the GTA line.
[3] Ex-franchise customers with contracts on the counter flowing paths always have the ability and capacity to flow on these paths within the limits of their contracts including on Design Day if they chose to do so.

TC Energy's Domestic Line at Parkway, and TC Energy's Niagara Export Pipeline at Kirkwall.

14. There are locations along the Dawn Parkway System which feed Enbridge Gas's distribution systems, directly connected customers, and interconnect pipeline operators. At these locations, gas is delivered to and / or received by Enbridge Gas's in-franchise and ex-franchise customers.

2.2. Panhandle Transmission System

15. The Panhandle System is comprised of parallel pipelines, a compressor station and measurement and regulating stations. The system starts at Dawn located in the Township of Dawn-Euphemia, southeast of the City of Sarnia, and extends to the Ojibway Valve Site (Ojibway) located in the City of Windsor. A map showing the overview of the Panhandle System is shown in Attachment 2.

16. The Panhandle System includes the following pipelines:
    a) NPS 36 pipeline (NPS 36 Panhandle Line) from Dawn to Dover Transmission Station (Dover Transmission) operating at a MOP of 6040 kPag;
    b) NPS 16 pipeline (NPS 16 Panhandle Line) from Dover Transmission to Grand Marais Station operating at a MOP of 4140 kPag[4]. The NPS 16 continues from Grand Marais Station to Ojibway operating at a MOP of 3450 kPag;
    c) NPS 20 pipeline (NPS 20 Panhandle Line) from Dawn to Sandwich Transmission Station (Sandwich) operating at a MOP of 6040 kPag. The

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[4] A portion of the NPS 16 pipeline from Ruscom Launcher/Receiver Site to Patillo Station was replaced with an NPS 20.

NPS 20 continues into the City of Windsor and connects with the NPS 16 near Grand Marais Station (referred to as the NPS 16/20 Junction) operating at a MOP of 3450 kPag;

d) Two NPS 12 pipelines (Detroit River Crossing) connect the NPS 16 Panhandle Line at Ojibway to the Panhandle Eastern Pipeline System (Panhandle Eastern)[5] at the International Border. This interconnection is commercially known as Ojibway. The Detroit River Crossing MOP is 2930 kPag; and

e) Four laterals which are connected to the NPS 20 Panhandle Line operating at a MOP of 6040 kPag (refer to the Legend in Attachment 3, numbers 1 through 4).

17. Dawn is the main source of supply to the Panhandle System. On design day, the flow of gas is westerly from Dawn towards Ojibway. System supply gas is also received at Ojibway which reduces the need for pipeline infrastructure and diversifies supply pathways. There is one compressor station located at Sandwich which is in the Town of Tecumseh. The Sandwich Compressor facilitates easterly transportation from Ojibway to Dawn during times when the Windsor market demand is insufficient to consume all supply coming from Ojibway. Ex-franchise customer gas flowing on paths which are opposite in direction (counter flowing) to the prevailing flow direction (i.e. Ojibway to Dawn) are not considered to be available for network analysis purposes on design day. The utilization of this path on design day is not controlled by Enbridge Gas and there is no contractual guarantee that ex-franchise customers will flow on this path[6].

[5] Panhandle Eastern Company, LP is owned by Energy Transfer Equity L.P.
[6] Ex-franchise customers with contracts on the counter flowing paths always have the ability and capacity to flow on these paths within the limits of their contracts including on Design Day if they chose to do so.

18. There are locations along the Panhandle System which feed Enbridge Gas's distribution systems, directly connected customers, and interconnect pipeline operators. At these locations, gas is delivered and / or received by Enbridge Gas's in-franchise and ex-franchise customers.

2.3. Sarnia Industrial Line System

19. The SIL is comprised of parallel pipelines including measurement and regulating stations. The SIL system starts at the Vector Courtright and Great Lakes Courtright Stations (collectively known as Courtright) located in St. Clair Township, the St. Clair Line Station (St. Clair) located in St. Clair Township, and Dawn located in the Township of Dawn-Euphemia. From Courtright, St. Clair and Dawn, the SIL system extends north to the Vidal Station located in the City of Sarnia. A map showing the overview of the SIL is provided at Attachment 3.

20. The SIL includes the following pipelines:
    a) NPS 12 from Courtright and St. Clair to the Sarnia Industrial Station operating at a MOP of 6620 kPag;
    b) NPS 20 from Courtright to the LaSalle Valve Site (LaSalle) operating at a MOP of 6620 kPag;
    c) NPS 16 Novacor Corunna Station (Novacor) to Dow Valve Site (Dow) operating at a MOP of 6620 kPag;
    d) NPS 10 inch runs from the Dow to the Churchill Road Station operating at a MOP of 6620 kPag;
    e) NPS 12 from Sarnia Industrial Station to Vidal Station operating at a MOP of 3450 kPag;
    f) NPS 8 and NPS 10 from Dawn and Novacor to McPlank Station operating at a MOP of 2890 kPag; and

g) NPS 20 from the Payne Pool Line to the Payne Transmission Station operating at a MOP of 6900 kPag. This pipeline connects to Dawn via the Payne Pool Line.

21. The SIL interconnects with the Vector Pipeline and TC Energy's Great Lakes Gas Transmission Pipeline at Courtright, located in St. Clair Township, the DTE/Michcon System via St. Clair Pipelines at the St. Clair Valve Site located in St. Clair Township, and the Bluewater Gas Storage System via St. Clair Pipelines, located in the City of Sarnia, at the Bluewater / Union Interconnect Valve Site (Bluewater).

22. Courtright and St. Clair are the main source of supply to the SIL. The flow of gas on the SIL on design day is northerly from Courtright towards Vidal Station. Ex-franchise customer gas flowing on paths which are opposite in direction (counter flowing) to the prevailing flow direction (i.e. Bluewater to Dawn, or St. Clair to Dawn) is not considered to be available for network analysis purposes on design day. The utilization of this path on design day are not controlled by Enbridge Gas and there is no contractual guarantee that ex-franchise customers will flow on this path[7].

23. There are locations along the SIL which feed Enbridge Gas's distribution systems, directly connected customers, and interconnect pipeline operators. At these locations, gas is delivered to and / or received by Enbridge Gas's in-franchise and ex-franchise customers.

24. The flow of gas on the SIL on design day is northerly from Courtright towards Sarnia Industrial Station.

[7] Ex-franchise customers with contracts on the counter flowing paths always have the ability and capacity to flow on these paths within the limits of their contracts including on Design Day if they chose to do so.

3. Design Day Information

25. The design day demand is the firm volumetric amount of natural gas Enbridge Gas must deliver to its customers (including ex-franchise customers), through its transmission systems, during the extreme cold weather event known as the design day. The design day demand process is provided at Exhibit 4, Tab 2, Schedule 3.

26. The existing in-franchise customers' design day demand was developed for this evidence using the actual customer demand data and weather data from winter 2021/2022. Company forecasts were added to the existing customer demand to predict the design day demand for the forecast period.

27. Some in-franchise customers have a component of their gas contract with Enbridge Gas called the Parkway Delivery Obligation (PDO) which is the requirement of some Union South rate zone in-franchise customers to deliver gas to the discharge side of Parkway on a firm basis. This PDO reduces the volume of gas transported from Dawn to Parkway on the Dawn Parkway System. Enbridge Gas forecasts the PDO and it is included in the design day analysis.

28. Enbridge Gas's forecast includes ex-franchise customers and in-franchise transportation requirements based on the outcome of open seasons and customer intelligence. The forecast is customer and transportation path specific.

29. The design day demand for Enbridge Gas's transmission systems is the sum of firm in-franchise customer demand for customers fed by the transmission systems in the Union South rate zone plus the demand transported to serve the EGD and Union North rate zones as per the Gas Supply Plan, as well as firm ex-franchise

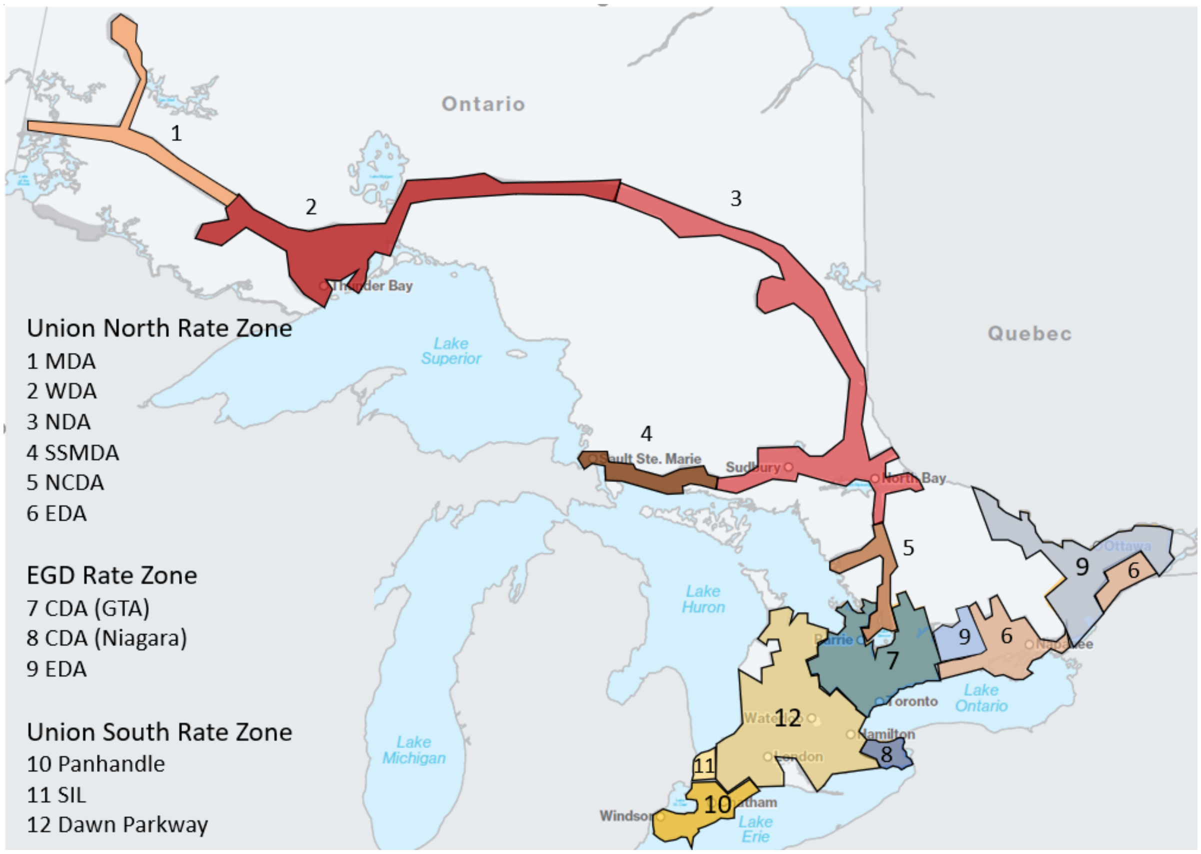
customer demand. In-franchise customers' interruptible demand is curtailed[8] on the design day and is not included as part of design day network analysis. The treatment of interruptible customers is proposed to be harmonized as provided at Exhibit 8, Tab 4, Schedule 2.

3.1. *Union South Rate Zone*

30. The Union South rate zone in-franchise customers are in Southwestern Ontario from the City of Windsor in the west, Grey County to the north, and the Regional Municipality of Halton in the east. The Panhandle System serves the Windsor/Chatham area, the SIL serves the Sarnia area, and the Dawn Parkway System serves in-franchise customers in the London, Waterloo, Brantford, Hamilton and Halton areas. These customers are served by laterals and downstream distribution systems connected to and located along the path of the transmission systems. Once the Union South rate zone design day demand is developed, Enbridge Gas determines the transportation contract requirements on the upstream transmission systems, peaking services and transportation requirements on the Dawn Parkway System. See Figure 2 for the Union South rate zone delivery areas.

[8] SIL summer and winter demands are similar as the power generation and large Petro-chemical manufacturers operate continually. If the pipeline system was designed for interruptible customers being curtailed, interruptible customers could seldom operate as the system would not have capacity for them to turn on, however for gas supply planning purposes on design day the interruptible customers are curtailed.

Figure 2: Enbridge Gas Delivery Areas



3.2. Union North Rate Zone

31. The Union North rate zone in-franchise customers are in northern and eastern Ontario in six delivery areas: Manitoba (MDA), Western (WDA), Northern (NDA), North Central (NCDA), Sault Ste Marie (SSMDA), and Eastern (EDA). These delivery areas are served directly from the TransCanada Mainline. The MDA serves the far western area of Ontario including the Town of Fort Frances. The WDA serves the area around the City of Thunder Bay. The NDA serves the area around the City of Greater Sudbury. The NCDA serves the Muskoka and City of Orillia areas. The SSMDA serves the area around the City of Sault Ste Marie, and the EDA serves the area between the Municipality of Port Hope and City of Cornwall.

Once the Union North rate zone design day demand is developed, Enbridge Gas determines the transportation contract requirements on upstream transmission systems like the TransCanada Mainline, peaking services and transportation requirements on the Dawn Parkway System. See Figure 2 for the Union North rate zone delivery areas.

3.3. EGD Rate Zone

32. The EGD rate zone in-franchise customers are in central and eastern Ontario in two delivery areas: central (CDA) and eastern (EDA). The CDA serves customers from the City of Mississauga in the west to the City of Oshawa in the east, and to the City of Barrie in the north, as well as the Niagara Peninsula. The EDA serves customers in the City of Peterborough in the west and the City of Ottawa in the east. Once the EGD rate zone design day demand is developed, Enbridge Gas determines the transportation contract requirements on the upstream transmission systems like the TransCanada Mainline and the Dawn Parkway System as well as peaking services. See Figure 2 for the EGD rate zone delivery areas.

3.4. *Ex-franchise*

33. Ex-franchise customers include customers in Québec, the Maritime provinces and the Midwestern and Northeastern United States, other Ontario based natural gas utilities, unbundled in-franchise customers and Union South rate zone in-franchise customers transporting their PDO. The ex-franchise customers contract for a specific level and specific path of transportation service on Enbridge Gas transmission systems. Enbridge Gas has the contractual commitment to provide, and the customer has the contractual right, to access their contracted demand on any day, including the design day. As a result, Enbridge Gas considers the design day demand for these customers to be equivalent to their contracted demand.

3.5. *System Supply*

34. The main source of supply for the Enbridge Gas transmission systems is the Dawn Hub. Dawn is one of North America's largest natural gas trading hubs and the largest underground storage facility in Canada with approximately 311 PJ/d of storage capacity. Multiple third-party upstream transmission pipelines converge at Dawn which access most major gas producing regions in North America. These pipelines include the Vector Pipeline, the Panhandle Eastern Pipeline (PEPL) via the Enbridge Gas Panhandle System, the Great Lakes Gas Transmission (GLGT) Pipeline, the DTE/Michcon System, the Bluewater Gas Storage system via the Enbridge Gas SIL System, and the ANR Pipeline via Niagara Gas Transmission (Niagara Link). These interconnect locations are shown in Figure 1and Attachments 1-3.

35. The Dawn Parkway System also receives supply via third party upstream transmission pipelines at Kirkwall from the TC Energy Niagara Export Line which connects to the import/export points at Niagara and Chippawa at the Ontario/New York border. At Parkway, Enbridge Gas can receive supply from the TransCanada Mainline which connects to multiple import / export points, including Empress at the Alberta/ Saskatchewan border and Niagara and Chippawa (via the TransCanada Domestic Line). These interconnect locations are shown in Figure 1 and Attachment 1 and discussed in Section 2.1.

36. The Panhandle System can also receive supply via the PEPL as discussed in Section 2.2. This interconnect location is shown in Attachment 1.

37. The SIL receives its primary gas supply from the Vector Pipeline, as well as supply from GLGT, DTE, Bluewater Gas Storage and Dawn as discussed in Section 2.3. These interconnect locations are shown in Attachment 3.

38. The transmission systems also receive supply from directly connected storage pools and local producers, including renewable natural gas producers.

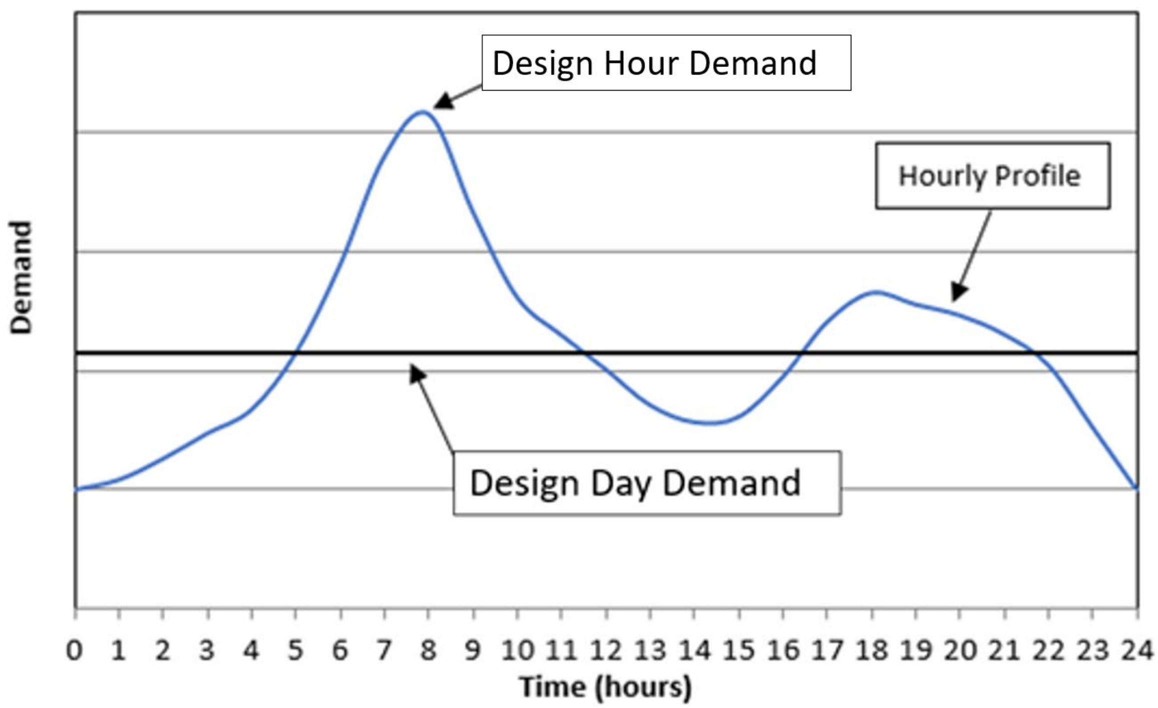
39. Some Union South rate zone customers are required to deliver their PDO to Parkway. Enbridge Gas considers the PDO in the capacity analysis of the Dawn Parkway System. This requirement reduces the amount of gas required to physically flow from Dawn to Parkway through Parkway compression.

3.6. Hourly Demand Profile

40. Enbridge Gas develops hourly demand profiles (profiles) for the delivery locations on the Dawn Parkway System and the Panhandle System using actual gate station data. Profiles are developed to model the demand variability over the design day. Locations where customers consume natural gas at a constant rate do not receive a variable profile.

41. The network analysis simulates the ability of each pipeline system to serve the design day demand at the critical morning uplift period which reaches its highest point around 8 a.m. and other time periods as required. A sample profile is shown in Figure 3.

Figure 3: Hourly Demand Profile Relationship between Design Day and Design Hour Demand



42. The Dawn Parkway System and Panhandle System are sized to serve the design day demand with the hourly demand changes served from the system's linepack. Linepack is the amount of natural gas storage within a pipeline and occurs because natural gas is compressible and becomes a usable asset in facilities design in large diameter, high pressure pipelines. When the hourly demand is greater than the design day demand the system pressure is dropping or known as "drafting" or losing linepack and when the hourly demand is less than the average daily demand the system pressure is increasing or known as "packing" or gaining linepack. The ability to use linepack in transmission systems reduces the need for facilities as the facilities can be sized for the daily demand rather than the design hour demand.

43. The SIL does not have sufficient linepack to serve the variability in the hourly demands. The SIL serves customers that operate continually at a constant rate and thus the SIL system is designed like a distribution system.

4. System Operating Criteria

44. Enbridge Gas's transmission systems have operating criteria to ensure safe and reliable operation. Each transmission system:

   a) Cannot operate above its MOP;
   b) Must operate above minimum contractual delivery pressures contained in customer contracts;
   c) Must operate above minimum suction pressure at compressor stations;
   d) Must operate within the aero assembly flow and head boundary conditions at the compressor stations;
   e) Must operate within flow and pressure constraints at measurement and regulating stations;
   f) Must transport the required supply and pressure available from Dawn and other supply sources; and
   g) Must maintain adequate loss of critical unit coverage at compressor stations.

4.1. Maximum Operating Pressure

45. It is necessary to design, operate and complete network analysis to maintain the system at or below the designated MOP to ensure the pipeline has the appropriate level of safety as required by the Z662 code[9]. The MOP of each Enbridge Gas transmission system is as follows:

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[9] Z662 is the Canadian Standards Association code book used to design the pipeline systems. Using the code Enbridge Gas will design the pipeline system's strength to resist the pipeline system operating pressure to allow the pipeline to operate in a safe and reliable manner at the pipelines MOP.

a) Dawn Parkway System is 6160 kPag;
b) Albion Line is 6450 kPag;
c) Panhandle System ranges from 2930 to 6040 kPag; and
d) SIL ranges from 2895 to 6895 kPag.

4.2. *Minimum Pressure*

46. It is necessary to ensure system pressures remain at or above the guaranteed contractual delivery pressures contained in customer contracts. This ensures the customer-owned gas-fired equipment can operate in a safe and reliable manner and maintains heat and continuity of commercial and industrial processes. This also ensures interconnect pipeline customers (such as the TransCanada Mainline) can continue to operate in a safe and reliable manner.

47. It is necessary to ensure system pressures remain at or above minimum inlet pressures at measurement and regulation stations. This ensures the downstream distribution systems have sufficient supply and pressure to reliably serve customer demand on design day.

48. Pressure must be maintained at or above the minimum suction pressures at Enbridge Gas compressor stations. This ensures that the compression equipment will operate within design conditions and are able to provide the required discharge pressure to maintain system capacity on design day.

49. The constraint location[10] minimum pressures on the Dawn Parkway System are as follows:

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[10] Constraint location means the location which is controlling or limiting system operation and capacity. There are many other minimum delivery pressure locations on the system however not all minimum delivery pressure locations are constraints.

a) The contractual minimum delivery pressure to the TransCanada Mainline (TransCanada Export Line) at Kirkwall is 4,480 kPag;
b) The contractual minimum delivery pressure to the TransCanada Mainline at Parkway is 6450 kPag and at Albion is 5760 kPag;
c) The minimum inlet pressure to the Enbridge Gas System at Parkway is 3450 kPag; and
d) The minimum suction pressure for the Lobo, Bright and Parkway compressor stations is 3,450 kPag.

50. The constraint location[11] minimum pressures on the Panhandle System are as follows:
   a) The contractual minimum delivery pressure to Brighton Beach Generating Station is 1724 kPag; and
   b) The minimum inlet pressure to the Leamington North Gate Station is 2275 kPag.

51. The constraint location[11] minimum pressures on the SIL are as follows:
   a) The contractual minimum delivery pressure to TransAlta Power Generating station is 3275 kPag; and
   b) The minimum inlet to the Sarnia Industrial Station is 3545 kPag.

4.3. Loss of Critical Unit Coverage

52. Pipeline systems flow from high to low pressure. High pressure is developed by compressing the gas at compressor stations. Pressure and system capacity are related. A higher system pressure increases pipeline capacity.

53. A gas compressor is a piece of mechanical equipment which reduces the gas volume resulting in increased pressure. The aero assembly contained within the compressor is rotated by a power turbine driven by the exhaust gas of an airplane jet engine. A compressor station is very complex with many pieces of equipment required to run the compressor. As with any complex piece of equipment, issues can develop that prevent the equipment from working optimally or from working at all.

54. The critical compressor unit is defined as the compressor unit that creates the greatest loss of system capability if it fails. This is typically the loss of the largest horsepower engine.

55. Dawn Parkway System LCU coverage (or reserve compression) is included in the design day analysis. This reserve compression has been installed and expanded over time and ensures all firm design day demand can be reliably served in the event of one unplanned compressor outage at each of Dawn, Lobo/Bright and Parkway. There is full LCU coverage for both the Parkway and Dawn compressor stations. Each of these stations have a spare compressor unit that provide compression horsepower in reserve and can be turned on when required. The Lobo and Bright stations do not each have dedicated spare compressor units. Instead, Lobo and Bright share reserve compression which protects the system capacity in the event of a compressor failure with the system capacity limited to loss of the critical compressor unit at either the Lobo or Bright compressor stations.

5. System Continuity

56. With the design day demand, supply and system operating criteria established, network analysis can be completed. Design day demand is proportioned to the

appropriate model locations based on the distribution system station flow rates. Physical properties of the pipeline system, compressor stations, and measurement and regulating stations are included. System flow and pressure are assessed to ensure all guaranteed minimum delivery pressures can be maintained, and that pipelines and all stations are operating within their design parameters. The results of the network analysis are used to determine if the existing infrastructure and gas supply arrangements have enough capacity to serve the design day demand within the boundaries set by the system operating criteria.

57. Locations where the modelled pressures are below minimum system pressure are identified. Solutions are identified to address areas of the system where modelled capacity is predicted to be less than the customer requirements. Alternatives are placed into the Asset Management Plan and reviewed and Integrated Resource Plan or facilities solutions are determined. Please see the Asset Management Plan at Exhibit 2, Tab 6, Schedule 2, Section 5.3.6, pages 194- 202 for additional information.

58. The System Continuity, which is the system capacity, design day demands, and surplus capacity for the Dawn Parkway System is shown in Table 1, the Panhandle System is shown in Table 2 and the SIL is shown in Table 3.

Table 1

Dawn Parkway System Continuity

					Parkway Deliveries(1)		
Line No.	Winter	System Capacity(2) (TJ/d)	Design Day Demand (TJ/d)	Surplus Capacity (TJ/d)	Union South (TJ/d)	EGD Ontario T-Service(3) (TJ/d)	Total (TJ/d)
		(a)	(b)	(c)	(d)	(e)	(f)
1	2023/2024	7,981	7,892	89	253	46	299
2	2024/2025	7,873	7,766	106	253	46	299
3	2025/2026	7,977	7,992	-15	339	46	385
4	2026/2027	8,030	8,012	18	336	45	381
5	2027/2028	8,029	8,035	-6	332	45	377
6	2028/2029	8,025	8,062	-37	329	45	374
7	2029/2030	8,179	8,089	90	327	45	372
8	2030/2031	8,178	8,115	63	324	44	368
9	2031/2032	8,178	8,142	37	321	44	365

Notes:

(1) Total Parkway deliveries for which the Parkway Delivery Commitment Incentive or market-based solution price will be applied. The market-based solution of approximately 26.5 TJ/d is included in the Union South total.

(2) There are small variances in the Dawn Parkway System capacity. As customer demand (both in-franchise and ex-franchise) changes at the various locations along the pipeline system the system capacity changes. Capacity also changes due to proposed infrastructure builds.

(3) The EGD Ontario T-Service Parkway deliveries have not been factored into the System Capacity or Design Day Demand of the Dawn Parkway System in columns (b) and (c). Had they been factored in, both the System Capacity and Design Day Demand would increase by the amount of the EGD Ontario T-Service Parkway deliveries with no change to the Surplus Capacity.

Table 2

Panhandle System Continuity

Line No.	Winter	System Capacity (TJ/d)	Design Day Demand (TJ/d)	Surplus Capacity (TJ/d)
		(a)	(b)	(c)
1	2023/2024	846	742	103
2	2024/2025	929	824	105
3	2025/2026	929	849	80
4	2026/2027	929	874	55
5	2027/2028	929	898	30
6	2028/2029	929	923	6
7	2029/2030	1,251	948	303
8	2030/2031	1,251	973	278
9	2031/2032	1,251	998	253

Table 3

Sarnia Industrial Line Continuity

Line No.	Winter	System Capacity (TJ/d)	Design Day Demand (TJ/d)	Surplus Capacity (TJ/d)
		(a)	(b)	(c)
1	2023/2024	703	690	13
2	2024/2025	703	690	13
3	2025/2026	703	690	13
4	2026/2027	703	690	13
5	2027/2028	703	690	13
6	2028/2029	703	690	13
7	2029/2030	718 (1)	690	28
8	2030/2031	718	690	28
9	2031/2032	718	690	28

Note:

(1) System capacity increase explained in Section 5.2.

5.1. *Dawn Parkway System Continuity*

59. In Winter 2023/2024, the Dawn Parkway System has a system capacity of 7,981 TJ/d. The capacity is comprised of the physical design day capacity of 7,728 TJ/d, plus the PDO of 253 TJ/d. There is a surplus of capacity of 89 TJ/d[11] relative to the demand of 7,892 TJ/d. Please see the map at Attachment 1 for additional detail.

60. For Winter 2026/2027, the additional facilities proposed to meet the increase in demand on November 1, 2026, is the Dawn Parkway Expansion Project (NPS 48 Kirkwall – Hamilton). This facility (or capacity alternative)[12] increases the system capacity by 53 TJ/d. The Dawn Parkway System has a system capacity of 8,030 TJ/d and is comprised of the physical design day capacity of 7,694 TJ/d, plus a PDO of 336 TJ/d. After the implementation of the proposed facilities (or capacity alternative) to meet the demand of 8,012 TJ/d, there remains a system surplus of 18 TJ/d.

61. For Winter 2029/2030, the additional facilities proposed to meet the increase in demand on November 1, 2029, is the Dawn Parkway Expansion Project (NPS 48 Dawn – Enniskillen). This facility (or capacity alternative)[16] increases the system capacity by 154 TJ/d. The Dawn Parkway System has a system capacity of 8,179 TJ/d and is comprised of the physical design day capacity of 7,852 TJ/d, plus a

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[11] Enbridge Gas is proposing the Dawn Parkway Surplus Capacity Deferral Account to record revenue from the sale of surplus Dawn Parkway System capacity during the IR term. Please see Exhibit 9, Tab 1, Schedule 3 for details of the proposed account.

[12] These future needs are assessed through the Integrated Resource Planning (IRP) process. Solutions to meet these future needs may include construction of new facilities (Facility Alternatives), contracting of commercial services, demand-side and supply-side Integrated Resource Planning Alternatives (IRPA), Enhanced Targeted Energy Efficiency projects (Non-Facility Alternatives) or a combination of both facility and non-facility alternatives (i.e., Hybrid Alternatives).

PDO of 327 TJ/d. After the implementation of the proposed facilities to meet the demand of 8,090 TJ/d, there remains a Dawn Parkway System surplus of 90 TJ/d.

5.2. <u>Panhandle System Continuity</u>

62. In Winter 2023/2024, the Panhandle System has a system capacity of 846 TJ/d which includes additional 120 TJ/d of capacity created by the Panhandle Regional Expansion Project[13] stage 1 NPS 36 looping from Dover Transmission to the Richardson Valve Site. The capacity is comprised of the physical design day capacity of 786 TJ/d, plus the Ojibway delivered volume of 60 TJ/d. There is a surplus of capacity of 103 TJ/d relative to the demand of 742 TJ/d. Please see the map at Attachment 2 for additional detail.

63. In Winter 2024/2025, the Panhandle System has a system capacity of 929 TJ/d which includes the capacity created by the Panhandle Regional Expansion Project[14] stage 2 Leamington Interconnect. The capacity is comprised of the physical design day capacity of 869 TJ/d, plus the Ojibway delivered volume of 60 TJ/d. There is a surplus of capacity of 105 TJ/d relative to the demand of 824 TJ/d.

64. In Winter 2024/2025, proposed replacement of the two NPS 12 river crossing pipelines (Panhandle Line Replacement) as part of the integrity program as detailed in the Asset Management Plan at Exhibit 2, Tab 6, Schedule 2, Section 5.3.6.2.2, page 198 will not increase the capacity of the Panhandle System. This project ensures 60 TJ/d of Ojibway volume Enbridge Gas contracts as part of the Gas Supply Plan will be a reliable supply to serve firm in-franchise demand on design day on the Panhandle System. If an acceptable solution cannot be negotiated with

[13] EB-2022-0157.
[14] Ibid.

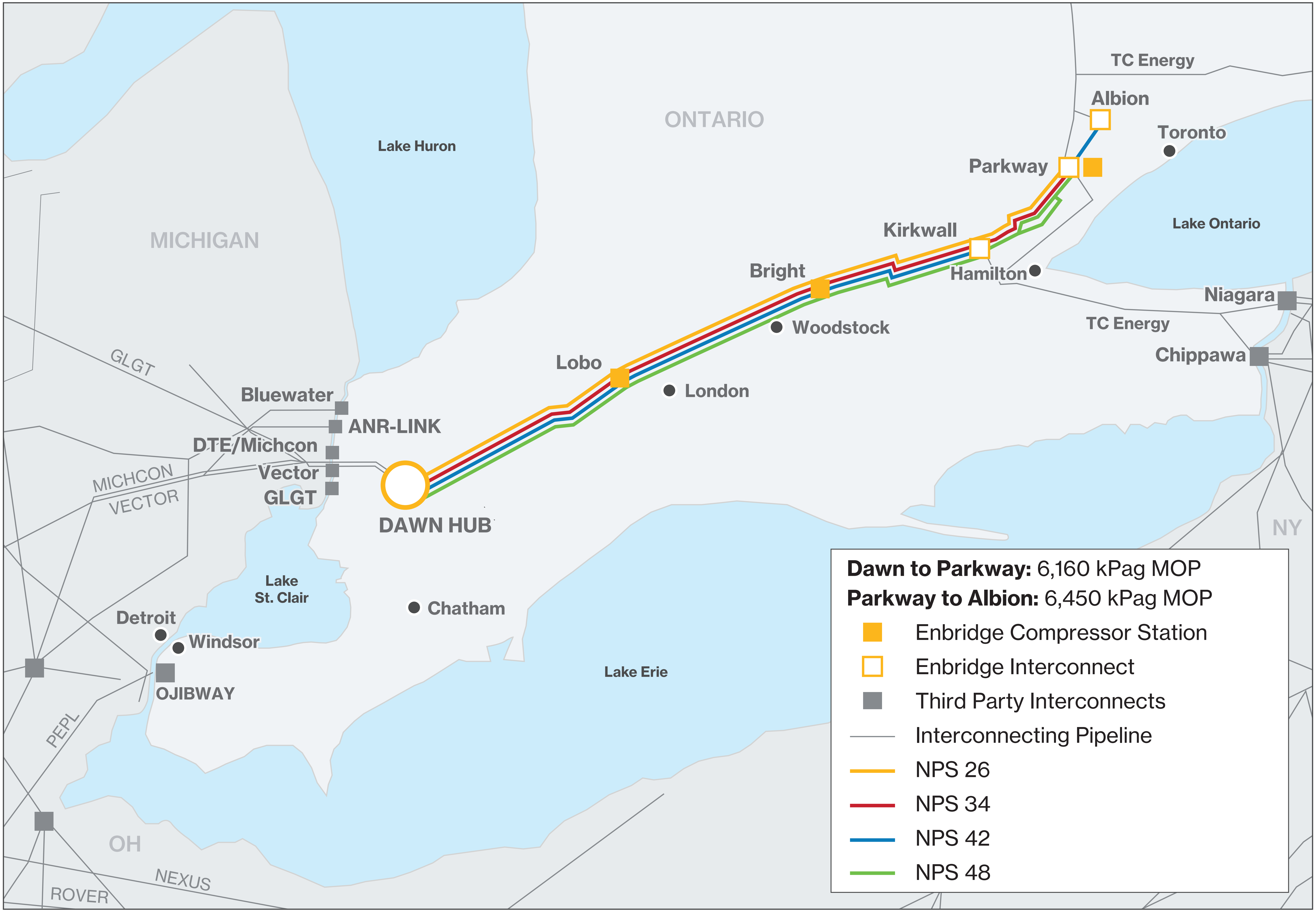
Panhandle Eastern, owner of the connecting pipeline in the United States, then alternatives will need to be considered, including shifting the 60 TJ/d of supply from Ojibway to Dawn.

65. For Winter 2029/2030, the additional facilities proposed to meet the increase in demand on November 1, 2029, is an NPS 36 looping from the Richardson Valve Site to Comber Transmission. This facility (or capacity alternative) increases the system capacity by 233 TJ/d. The Panhandle System has a system capacity of 1,251 TJ/d and is comprised of the physical design day capacity of 1,191 TJ/d, plus Ojibway deliveries of 60 TJ/d. After the implementation of the proposed facilities to meet the demand of 948 TJ/d, there remains a system surplus of 303 TJ/d.

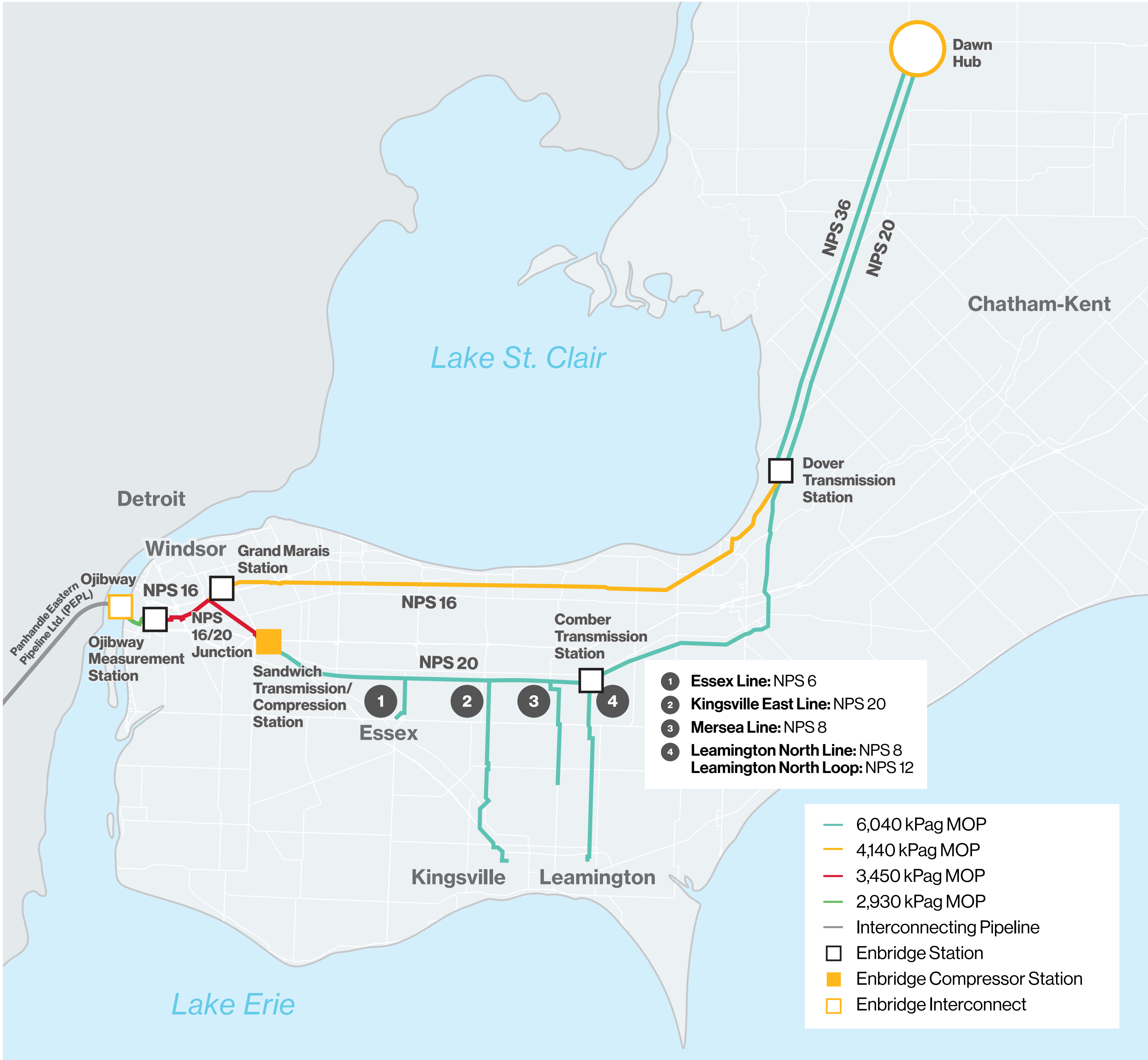
5.3. *Sarnia Industrial Line Continuity*

66. In Winter 2023/2024, SIL has a system capacity of 703 TJ/d. There is a surplus of capacity of 13 TJ/d relative to the demand of 690 TJ/d. Please see the map at Attachment 3 for additional detail.

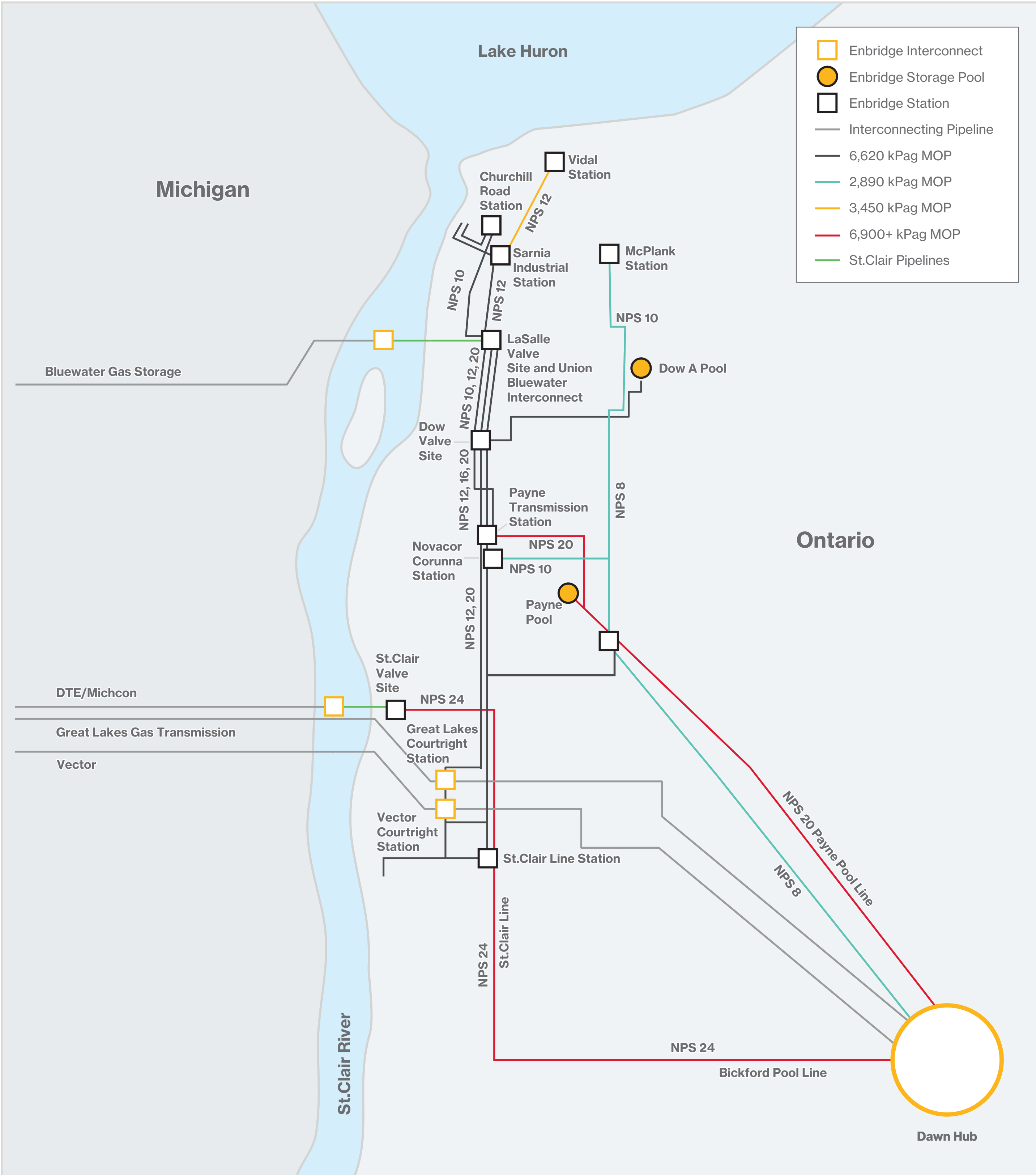
67. For Winter 2029/2030, the additional facilities proposed for November 1, 2029, is the Sarnia Industrial Station Rebuild. This facility rebuild increases the system capacity by 15 TJ/d to a system capacity of 718 TJ/d. While there is currently no forecast growth in the SIL system, there are frequent requests for capacity from prospective industrial customers and this project would be available to serve increased demand. After the implementation of the proposed facilities to meet the forecast demand of 690 TJ/d, there remains a system surplus of 28 TJ/d.



TC Energy
Albion
Toronto
ONTARIO
Lake Huron
Parkway
Lake Ontario
Kirkwall
MICHIGAN
Bright
Hamilton
Niagara
Woodstock
TC Energy
GLGT
Chippawa
Lobo
London
Bluewater
ANR-LINK
DTE/Michcon
MICHCON
Vector
VECTOR
GLGT
DAWN HUB
NY
Lake St. Clair
Chatham
Detroit
Windsor
OJIBWAY
Lake Erie
PEPL
OH
NEXUS
ROVER
Dawn to Parkway: 6,160 kPag MOP
Parkway to Albion: 6,450 kPag MOP
Enbridge Compressor Station
Enbridge Interconnect
Third Party Interconnects
Interconnecting Pipeline
NPS 26
NPS 34
NPS 42
NPS 48



Dawn Hub
NPS 36
NPS 20
Chatham-Kent
Lake St. Clair
Dover Transmission Station
Detroit
Windsor
Grand Marais Station
Ojibway
NPS 16
Panhandle Eastern Pipeline Ltd. (PEPL)
NPS 16/20 Junction
NPS 16
Ojibway Measurement Station
Sandwich Transmission/ Compression Station
NPS 20
Comber Transmission Station
1
2
3
4
Essex
Kingsville
Leamington
Lake Erie
1 Essex Line: NPS 6
2 Kingsville East Line: NPS 20
3 Mersea Line: NPS 8
4 Leamington North Line: NPS 8
Leamington North Loop: NPS 12
6,040 kPag MOP
4,140 kPag MOP
3,450 kPag MOP
2,930 kPag MOP
Interconnecting Pipeline
Enbridge Station
Enbridge Compressor Station
Enbridge Interconnect



Lake Huron
Michigan
Ontario
St.Clair River
Enbridge Interconnect
Enbridge Storage Pool
Enbridge Station
Interconnecting Pipeline
6,620 kPag MOP
2,890 kPag MOP
3,450 kPag MOP
6,900+ kPag MOP
St.Clair Pipelines
Vidal Station
Churchill Road Station
Sarnia Industrial Station
McPlank Station
NPS 12
NPS 10
NPS 12
NPS 10
LaSalle Valve Site and Union Bluewater Interconnect
Bluewater Gas Storage
Dow A Pool
NPS 10, 12, 20
Dow Valve Site
NPS 12, 16, 20
NPS 8
Payne Transmission Station
NPS 20
Novacor Corunna Station
NPS 10
Payne Pool
NPS 12, 20
St.Clair Valve Site
DTE/Michcon
NPS 24
Great Lakes Gas Transmission
Great Lakes Courtright Station
Vector
Vector Courtright Station
St.Clair Line Station
NPS 20 Payne Pool Line
NPS 8
NPS 24
St.Clair Line
NPS 24
Bickford Pool Line
Dawn Hub

ADVANCED METERING INFRASTRUCTURE

LOUIE JEROMEL, TECHNICAL MANAGER ENGINEERING INTEGRATION

1. The purpose of this evidence is to provide an overview of how Advanced Metering Infrastructure (AMI) is being considered for use within Enbridge Gas and to update the OEB on the Company's intention to file a comprehensive AMI proposal in the future. The evidence summarizes Enbridge Gas's progress and activities related to developing an AMI proposal as well as its benefits.

2. This evidence is organized as follows:
    1. AMI Background
    2. Current State/Situation
    3. Future Plans to File an AMI Application

1. AMI Background

3. AMI is an integrated system of meters (i.e. ultrasonic), end points, communications networks, and data management systems that enable two-way communication between utilities and customer meters.

4. Enbridge Gas is currently reviewing the opportunity to automate its meter reading process for customers. Automation refers to the ability to communicate with meters at customer premises to collect gas consumption, remotely activate various alarms, and collect other key diagnostic information. An AMI solution would drive operational efficiencies while providing viable technological solutions and value-based opportunities for its customers.

5. Currently Enbridge Gas relies on an external provider to read the vast majority of its meters on a bi-monthly basis. This practice is highly manual, vulnerable to errors

and can be inconvenient to customers; further, the utility industry is overwhelmingly moving towards some form of meter automation, leading to changes in both market conditions and customer expectations. Automation is more accurate and convenient for customers while allowing operational efficiencies to be achieved for the utility and additional insight for customers as they are able to see further details on their gas consumption patterns.

6. Early indications from customers through customer engagement revealed that there is a desire to have the features and benefits that AMI provides. Please see Exhibit 1, Tab 6, Schedule 1, Attachment 1, page 16 for a summary.

7. AMI has emerged as the industry standard for utility meter reading, thereby changing manufacturer diaphragm metering product availability. A major North American meter supplier has ceased the production of diaphragm meter technology to focus on their ultrasonic product line. This has created and will continue to create supply chain constraints on Enbridge Gas's ability to effectively manage its meter assets.

8. Across North America, many gas utilities such as Atmos Energy, Con Edison, Nicor Gas, Southern California Gas, and Pacific Gas and Electric Company, being approved in their regulated jurisdictions to implement AMI, have transitioned away or are in the process of transitioning away from manual meter reading. AMI is no longer deemed emerging or "cutting-edge" within the utility sector.

9. FortisBC Energy Inc. is currently pursuing approval from the British Columbia Utilities Commission (BCUC) for the replacement of all existing customer diaphragm meters, approximately 1,000,000 meters, with AMI infrastructure.[1]

10. An AMI solution at Enbridge Gas would have numerous benefits:
    a) AMI would allow Enbridge Gas to begin gathering hourly consumption data from customers whose meters are currently read manually, which would provide improved system insight to better inform system planning efforts, enabling more detailed system modelling and inform individual customer peak usage. This will lead to an increased understanding of the effectiveness of Integrated Resource Planning Alternatives (IRPA) and reduce risk associated with deferring capital reinforcement projects. Also, the enhanced information can be leveraged by Demand Side Management (DSM) programs to understand impacts and identify target customers for future offerings.
    b) AMI will allow Enbridge Gas to address many of the challenges around the Meter Reading Performance Metric (MRPM). The ability to attain reads digitally will allow for consistent meter reading throughout the year, alleviate consecutive estimated reads due to severe weather events (e.g freezing rain, polar vortex, flooding, heavy snowfall), meter access issues which have limited the ability to read meters manually and also eliminate the difficulty in finding and retaining meter reading staff. Please see Exhibit 1, Tab 7, Schedule 1, Section 2.4 for further details on Enbridge Gas's MRPM.

[1] FortisBC Energy Inc. Application for a Certificate of Public Convenience and Necessity for the Advanced Metering Infrastructure Project, BCUC File 65152.

c) AMI allows for real-time alerts, the remote control of gas meters to better react in emergency situations, enables potential load shedding that may be required due to upstream supply issues, and helps identify gas theft and tampering. Although the ability exists to remotely operate an internal valve within the meter, it would not be Enbridge Gas's position to do so unless in an emergency situation, nor without an on-site safety inspection upon reactivation. Methane sensors can also be installed for indoor meter sets.

d) One of the key focus areas for energy policy in Ontario identified by the Ontario Energy Association's (OEA) 2022 Energy Platform is the optimal use of existing energy infrastructure.[2] As detailed by the OEA, to best leverage the existing natural gas system, one mechanism is to "Implement Automated Metering for natural gas customers to support and monitor DSM initiative, promote usage awareness, and encourage behaviour change."[2]

e) AMI provides increased system insight which will be of benefit as the gas composition and supply changes with the introduction of blending green fuels such as Renewable Natural Gas (RNG) and hydrogen. Challenges exist with system planning modelling (e.g. determining takeaway capacity, balancing the system in off-peak conditions) due to localized green fuel injection in the distribution system. With AMI providing a better understanding of how customers use natural gas during warmer summer conditions, Enbridge Gas will be able to optimize local RNG/H2 injection.

f) AMI supports Greenhouse Gas (GHG) emission reductions related to meter reading vehicles being eliminated. With the capability of real-time alerts, remote diagnostics and troubleshooting, AMI could reduce the number of vehicles being dispatched. Also, the advancement of measurement accuracy with ultrasonic meters would assist in the determination of unaccounted for

[2] Ontario Energy Association, Energy Platform (2022), Recommendation 2B, p. 3.

gas. Additionally, the network required for AMI allows for the future addition of sensors that can better identify gas leaks or cathodic failures.

2. Current State/Situation

11. Enbridge Gas previously made submissions regarding AMI with the OEB and intervenors during the Integrated Resource Planning proceeding[3], indicating that an AMI proposal would be filed at a future date. Since that time, Enbridge Gas has continued to explore the opportunity to implement AMI and has made significant progress in understanding the Company's options and the relative costs and benefits. However, Enbridge Gas is not prepared to file a fully documented business case or proposal as part of the current rebasing application.

12. Enbridge Gas is planning to complete a Proof of Concept (POC) of AMI technology. This POC will allow Enbridge Gas to better understand the technology, gain hands-on experience with the assets, mitigate issues and risks of the planning and execution process as well as inform a comprehensive application. There have also been delays with Measurement Canada approvals for the use of the meters in Canada which have pushed out the commencement of the POC. Although specific timing of the regulatory approvals is unknown at this time, they are anticipated to occur over the next few months.

13. There are no capital costs associated with the AMI assessment project included in the AMP submitted to the OEB within the rebasing application.

[3] EB-2020-0091 – Exhibit A, Tab 13; Exhibit B – Additional Evidence; Various Interrogatory Responses; Argument-in-Chief (March 17, 2021).

3. Future Plans to File an AMI Application

14. Enbridge Gas plans to file a stand-alone AMI Application as soon as practically possible requesting approval from the OEB for the funding and implementation of an AMI solution.

15. Enbridge Gas remains committed to AMI as an important technology in the evolution of Enbridge Gas's position as a leader in the energy delivery sector, driving operational efficiencies while providing viable solutions and value-based services and opportunities for its customers.